Addressing uncertainty in oil and natural gas industry greenhouse gas inventories

Technical considerations and calculation methods

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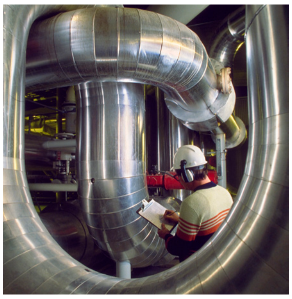

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Acronym List

ADEME	French Environment and Energy Management Agency
AF	Activity Factor
AGA	American Gas Association
ANSI	American National Standards Institute
API	American Petroleum Institute
ASTM	American Society of Testing and Materials
AWP	Alternative Work Practice
BOE	Barrels of Oil Equivalent
BTU	British Thermal Unit
CARB	California Air Resources Board
CDP	Carbon Disclosure Project
CE	Calibration Error
CEMS	Continuous Emissions Monitoring System
CER	Clean Energy Regulator
CH4	Methane
CIP	Chemical Injection Pumps
CO2	Carbon Dioxide
CORINAIR	The Core Inventory of Air Emissions in Europe
DP	Differential Pressure
DQI	Data Quality Indicators
EDR	Electronic Data Reporting
EF	Emission Factor
eGGRT	Electronic GHG Reporting Tool
EIPP	Emissions Inventory Improvement Program
EJ	Exajoules
EMEP	European Monitoring and Evaluation Programme
EPA	Environmental Protection Agency
ERCB	Energy Resources Conservation Board
ETS	European Union Emissions Trading System
ETSG	ETS Support Group
EU	European Union
EVCI	Electronic Volume Conversion Instrument
FCCU	Fluid Catalytic Cracking Unit
FID	Flame Ionization Detector
FFMS	Flare Flow Measurement System
GC	Gas Chromatography
GHG	Greenhouse Gas
GHGRP	GHG Reporting Program
Gj	Gigajoule
GOR	Gas-to-Oil Ratio
GPA	Gas Processors Association
GWP	Global Warming Potential
HHV	Higher Heating Value
Hp	Horsepower
INGAA	Interstate Natural Gas Association of America
IPCC	Intergovernmental Panel on Climate Change
IPIECA	Global oil and gas industry association for environmental and social issues
ISO	International Standards Organization
kW	Kilowatt
kWh	Kilowatt-hour
l	Liter
LACT	Lease Automatic Custody Transfer
LHV	Lower Heating Value
LPG	Liquefied Petroleum Gas
MJ	Megajoules
MRG	Monitoring and Reporting Guidelines
MPMS	Manual of Petroleum Measurement Standards
NGER	National Greenhouse and Energy Reporting
Nm3	Normal Cubic Meters
OBQ	On-board Quantity
OECD	Organization for Economic Cooperation
IOGP	International Oil and Gas Producers Association
OSCAR	Online System Comprehensive Activity Reporting
OVA	Organic Vapor Analyzer
PD	Positive Displacement
PEI	Primary Element Inspection
PPM	Parts Per Million
ROB	Remaining on Board
SAR	Second Assessment Report
SI	International System of Units
t	tonne
TJ	Terajoule
TCD	Thermal Conductivity Detector
TVA	Toxic Vapor Analyzer
UNFCCC	United Nations Framework Convention on Climate Change
VEF	Vessel Experience Factor
VEFD	Vessel Experience Factor on Discharging
VEFL	Vessel Experience Factor on Loading
VOC	Volatile Organic Compounds
WBCSD	World Business Council for Sustainable Development
WCI	Western Climate Initiative
WRI	World Resources Institute

INTRODUCTION

The global petroleum and natural gas industry has been active in promoting consistency and harmonization for industry greenhouse gas (GHG) emission inventories. Industry associations and their members have been contributing to the development of guidance for accounting and reporting of GHG emissions (API/IPIECA/OGP, 2011), and compiling methodologies that are appropriate for estimating GHG emissions from industry operations (API, 2009). This guidance has been recently augmented with guidelines to account for reductions associated with GHG projects (API/IPIECA, 2007a).

The uncertainties inherent in the data used for emission inventories help inform and improve understanding of the data's use. The uncertainty of petroleum and natural gas companies' GHG emission inventories, or of its quantified emission reductions, is determined largely by uncertainties in the estimates of the key (largest) contributing sources. In turn, each of these uncertainties depends on the quality and availability of sufficient data to estimate emissions. The robustness of industry data disclosures is receiving increased attention with special emphasis on the need to understand how GHG emissions and emission reductions are quantified.

Background

The American Petroleum Institute (API), Concawe (the scientific and technical organization of the European petroleum refining industry) and the The global oil and gas industry association for environmental and social issues (IPIECA) convened an international workshop on the topic on 16 January 2007, in Brussels, Belgium. The goals of this workshop were to:

- develop an understanding of the relative importance of the key factors that contribute to uncertainty;
- review and discuss emerging techniques for quantitative assessment of the uncertainty and accuracy of GHG emissions estimates;
- identify emission sources and methods where petroleum and natural gas industry efforts are needed to improve accuracy and reduce uncertainty to acceptable levels; and
- create a prioritized list of topics to be addressed by the petroleum and natural gas industry to minimize emissions estimation uncertainty and improve data accuracy.

A summary report, as well as all the workshop presentations, is posted on the IPIECA website (API/IPIECA, 2007b, http://www.ipieca.org/publication/greenhouse-gas-emissions-estimation-and-inventories-addressing-uncertainty-and-accuracy).

The 2007 workshop served as the first step in addressing uncertainty and accuracy issues. In the ensuing industry discussion, a list of priority issues was prepared. This list is comprised of items that industry experts ought to address in a systematic fashion. As presented in the workshop summary report, the issues listed by industry members fall into three thematic areas:

1. Measurement methods
2. Computational methods
3. External communications

Because the industry recognizes the need for meeting regulatory mandates and stakeholders' expectations, follow-up activities will be designed to provide opportunities for continued dialogue and collaborative activities with stakeholders.

A pilot version of this document was published in September 2009 to allow broad review and implementation of guidance provided by all stakeholders. Comments received, lessons learned, and new developments that have occurred in the area since then are now summarized in this final guideline document.

Document goals

The goals of these guidelines are to:

- Summarize in a single document guidance for meeting data needs of a range of voluntary and mandatory initiatives, as well as the requirements of diverse GHG regimes;
- Supplement existing industry guidance and provide technically valid approaches for use by the global petroleum and natural gas industry to improve GHG emissions estimation robustness and data quality; and
- Provide a practical and easy to implement approach for a range of applications starting with establishing a corporate carbon footprint, publicly reporting GHG emissions, and assessing lifecycle emissions.

The technical considerations and statistical calculation examples included in this document are designed to provide technically sound approaches for assessing uncertainty in different situations, but they do not represent an industry standard. The discussion will include: clarification of the sources of uncertainty in GHG inventories; information on measurement practices and their associated uncertainties; overview of different emerging regulatory approaches to ensuring quality of emission estimation data; and explanation of statistical procedures and tools that can be used to quantify uncertainties. The case studies included are for illustrative purposes and demonstrate options that may be available for practical implementation of the recommended approaches.

DOCUMENT AT A GLANCE

This document is designed to provide a summary of technical considerations that are important for understanding and calculating GHG emission inventory uncertainty. The document provides technical background and specific calculation methods to determine uncertainties with targeted measurements and emission factors, and to determine how to aggregate these individual terms to derive uncertainty ranges (at a pre-designated probability level) for entire GHG inventories at any given level.

These emission inventories of typical petroleum and natural gas systems operations are quite complex; they are based on a combination of measured and estimated emissions data, according to local requirements and available information. The overall range of uncertainty associated with an entity GHG inventory is determined primarily by the uncertainty associated with the largest ("key") sources of emissions. In turn, the confidence interval associated with each individual source depends on the availability of sufficient data to estimate emissions, or on the quality of that data, in order to properly account for emission variability.

Uncertainty analysis is a potential tool to not only assess confidence intervals, but more importantly to allow the targeting of specific areas for enhanced data collection. Such an analysis will enable a user to prioritize emission sources in terms of their overall contribution to the emissions inventory and its overall uncertainty range.

This document is a companion to the API *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry* (API, 2009). It provides a range of background information on industry practices and specific calculation methods that will enable inventory developers to quantify and better understand the uncertainty associated with the resultant GHG emissions.

Section 1 introduces some basic concepts and terms that provide a foundation for understanding GHG emissions inventory uncertainty. This terminology is used throughout the document. Section 1 covers: the importance of reliable GHG accounting; a terminology overview; definition of error types; and a description of the determination of uncertainty ranges (also known as confidence intervals).

Section 2 discusses the major sources of uncertainty in GHG inventories. It moves from general concepts to issues that are relevant to GHG inventories in the petroleum and natural gas industry. It also describes factors that could introduce errors into the emission measurement process and contribute to the range of uncertainties of estimated emissions. It introduces the categories of emission estimation approaches and their uncertainty implications, and concludes with a short description of emission inventory steps and data aggregation.

Section 3 provides an overview of measurement practices, focusing on gas flow measurements and the determinations of carbon content and heating values of combusted fuels. The section recognizes industry-recommended practices and standards that have traditionally applied to "custody transfer". This section goes on to discuss data considerations when collecting information on activity levels and applicable GHG emissions. It includes an overview of measurement practices that would result in high quality data when properly implemented, while focusing on measurements that are applicable to the key contributing sources, i.e. carbon dioxide (CO_2) emissions from combustion devices. Topics discussed include: flow measurement practices; uncertainties of flow measurements for GHG inventories; uncertainty of sampling and analysis for GHG estimation; and laboratory management systems.

Section 4 provides an overview of the uncertainty requirements from various GHG reporting programs applicable to the petroleum and natural gas sector and compares elements of programmes and their uncertainty targets. Where available, calculation tools available to assist reporters in quantifying the uncertainty of GHG emission estimates for these programs are also introduced.

Section 5 outlines uncertainty principles and introduces general calculation and aggregation approaches. This section also discusses reducing uncertainty in the context of improving GHG data quality.

Detailed technical information is organized in appendices (available in a separate document), as follows:

- ***Appendix A***: Glossary of statistical and GHG inventory terms
- ***Appendix B***: A comprehensive list of applicable industry measurement standards
- ***Appendix C:*** Operating conditions, inspection, calibration and manufacturers' reported measurement errors for common flow meters
- ***Appendix D***: Measurement method summaries for carbon content measurement methods and heating value measurement methods
- ***Appendix E***: Unit conversions including energy units, common units of measure for fossil fuel heating content values, and carbon content of selected fuels
- ***Appendix F:*** Tutorial on statistical concepts and calculations
- ***Appendix G***: Calculation details for uncertainty estimation for an example oil and natural gas production facility GHG inventory
- ***Appendix H:*** Calculation details for uncertainty estimation for an example refinery GHG inventory.

1. INTRODUCTION

Policymakers use entity GHG inventories and reported facility-level GHG emissions to develop strategies and policies for emission reductions and to track the progress of these policies. Both regulatory agencies and corporations rely on inventories to better understand emission sources and trends. GHG inventory data are associated with varying degrees of uncertainty, and such actual uncertainties have both technical and policy implications.

"Uncertainty analysis" has been increasingly recognized as an important tool for improving national, sectoral, and corporate inventories of GHG emissions and removals (IPCC, 2000). This increased attention on accurate inventories has resulted in the need to provide guidance to industry on technical considerations and calculation methods for consistent estimation of GHG inventory uncertainty. This typically would consist of:

- determination of the uncertainties associated with the individual measurements and factors used in constructing the emissions inventory; and
- propagation and aggregation of these individual terms to derive uncertainty intervals (at a pre-designated probability level) for the whole inventory.

The extent and scope of such analysis will depend on the likely uses of this information. For example, the uncertainty analysis required for data that are merely used for relative ranking or comparison of trends would be different from that required to demonstrate attainment of GHG emission limits or progress made towards meeting GHG emission reduction targets.

1.1 Importance of accurate and reliable GHG accounting

Key areas that benefit from reliable GHG accounting include:

- focused GHG emissions management;
- reduced business risk and reputation management; and
- participation in GHG emissions mitigation programs.

Comparability, Consistency, Certainty, Confidence

SECTION FOCUS

This is an introductory section that introduces some basic concepts and terms that are the foundation for understanding GHG emissions inventory uncertainty. This terminology will be further expanded throughout the next sections of the document.

The subsections include:

- Importance of accurate and reliable GHG accounting;
- Overview of uncertainty terminology;
- Types of errors;
- Numerical determination of uncertainty intervals; and
- Emissions inventory uncertainty assessment.

Since an understanding of the magnitude and sources of GHG emissions is critical for properly managing these emissions, using a consistent approach can significantly improve industry-wide, comparable estimates of emissions and emission reductions.

Higher-quality GHG data lead to higher certainty of emission assessments and improved confidence in the data reported. This is true for national and government assessments, and is also important at the entity or facility level. To ensure that a company's strategies and forward-looking actions are based on the most robust data set and most appropriate computational methods, it is important to address the following factors:

a. *Comparability*: Uncertainty analysis enables comparison of data trends and between entities.

a. *Consistency*: Science-based estimation and measurement methods should include consideration of accuracy and precision.

a. *Certainty:* Emission inventories are estimates; uncertainty analysis provides a likely range of those estimates.

a. *Confidence*: Users of the inventory need to understand the reliability of the estimated emissions, especially when they are used for policy development, or to target inventory improvements.

1.2 Overview of uncertainty terminology

In Chapter 13 of its *Manual of Petroleum Measurement Standards* (MPMS), the API provides detailed guidance on concepts and procedures for addressing the statistical procedures that should be followed when estimating a true quantity from measurements - or models – and when deriving the confidence interval of the results (API, 1985). That chapter also examines sources of error and recommends how to develop a statement of the overall range of uncertainty of the results obtained. Some of the key terms used in the API MPMS are presented in Exhibit 1-1.

Appendix A presents an expanded glossary of statistical terms with comments on how these terms are used in the context of GHG emission inventories.

This terminology is also used by the Intergovernmental Panel on Climate Change (IPCC) as part of their 'Good Practice Guidelines' for managing and estimating uncertainty in national emission inventories (IPCC, 2000), which provides a conceptual basis for uncertainty analyses. The IPCC guidelines introduce a structured approach to estimating GHG inventory uncertainty by incorporating methods used to determine uncertainties of individual terms and aggregate them to the total inventory. The IPCC also recognizes that other uncertainties may exist, such as those arising from inaccurate definitions or procedures, which cannot be addressed by statistical means.

EXHIBIT 1-1: SELECTED TERMINOLOGY

- **Accuracy** – Ability to indicate values that closely approximate the true value of the measured variable.
- **Bias** – Any influence on a result that produces an incorrect approximation of the true value of the variable being measured. Bias is the result of a predictable systematic error.
- **Confidence interval (or range of uncertainty)** – The range or interval within which the true value is expected to lie with a stated degree of confidence.
- **Confidence level** – The degree of confidence that may be placed on an estimated range of uncertainty.
- **Error** – The difference between true and observed values.
- **Precision** – The degree to which data within a set cluster together.
- **Random error** – An error that varies in an unpredictable manner when a large number of measurements of the same variable are made under effectively identical conditions.
- **Spurious error** – A gross error in procedure (for example, human errors or machine malfunctions).
- **Systematic error** – An error that, in the course of a number of measurements made under the same conditions on material having the same true value of a variable, either remains constant in absolute value and sign, or varies in a predictable manner. Systematic errors result in a bias.
- **Variance** – The measure of the dispersion or scatter of the values of the random variable about the mean.

Source: API MPMS Chapter 13.1 (API, 1985 and 2011)

1.3 Types of errors

The difference between the observed value of a variable and its true value includes all errors associated with a given measurement or estimation process. Such errors are comprised of instrumentation errors, errors resulting from faulty sampling procedures, changes in conditions during the measurement period, or use of improper methods. Three basic types of errors should be considered:

- spurious errors;
- systematic errors; and
- random errors.

One or all of these errors could be associated with individual measurements or input variables used for deriving an emissions inventory, though such individual errors should not be confused with the overall inventory uncertainty. The overall uncertainty of the emission inventory is comprised of the weighted individual errors as further discussed in Section 5.2 with examples in Section 5.3.

Indicators such as the range, confidence interval or other error bounds are typically used to quantify an emission estimate uncertainty. Errors may be due to the inherent variability of the emission processes and the bias – or imprecision – in the terms typically used to define them. Bias is the result of a systematic error in some aspect of the emissions inventory process. In contrast, imprecision is due to random errors or fluctuations in the measurement process.

1.4 Numerical determination of uncertainty intervals

The uncertainty intervals associated with input quantities (such as measured emission rates, activity data or emission factors) are characterized by the dispersion of the respective values that are used in their derivation. Mathematically these intervals are defined as either the standard deviation of the sample populations or the standard deviation of the sample means. The standard deviation of the mean, known also as the standard error of the mean, is the standard deviation of the sample data set divided by the square root of the number of data points. While the standard deviation and variance of the data set do not change systematically with the number of observations, the standard deviation of the mean decreases as the number of observations increases.

Estimating uncertainties in emission inventories is based on the characteristics of the variable(s) of interest (input quantities) as estimated from the corresponding data set. The statistical computations could entail the determination of:

- the arithmetic mean (mean) of the data set;
- the standard deviation of the data set (the standard error, the square root of the variance);
- the standard deviation of the mean (the standard error of the mean);
- the probability distribution of the data; and
- covariance of the input quantity with other input quantities used in the inventory calculations.

These calculation methods are discussed in the context of estimating uncertainty in Section 5.0.

The limits of the confidence interval associated with GHG emissions from a source are directly dependent on the probability distribution, or the probability function, used to represent that data set. The quantification of uncertainty intervals for GHG emissions will depend both on the uncertainty of measurements, its representativeness, and the assumed distributions of other key parameters that are an integral part of emission estimation. General rules for evaluating and expressing uncertainty may be followed at various levels in many fields (ISO, 2005; ISO, 2008; IPCC, 2000).

1.5 Emissions inventory uncertainty assessment

Several types of parameters are closely linked in general with emissions inventory development and the assessment of its uncertainty:

- direct emissions data;
- activity data; and
- emission factors.

The uncertainty of these parameters can be represented by either a probability distribution or as a range. Common distributions include, but are not limited to, the normal distribution, lognormal distribution, uniform distribution, and triangular distribution (Lloyd, 2007). For activity data and emission factor data, the log-normal distribution is often determined to be a reasonable fit.

Different approaches to quantifying parameter uncertainty may include:

- measured uncertainty (represented by standard deviations);
- uncertainty factors for specific activities or sector data (reported in literature);
- probability distributions from available databases; and
- the pedigree matrix approach, based on data quality indicators (DQIs).

While this guidance focuses on quantifying parameter uncertainty from measurements, activity data, and emission factors, the pedigree matrix approach may also be applicable as further elaborated in the following sections.

2. ASSESSMENT OF UNCERTAINTY RELEVANT TO GREENHOUSE GAS EMISSION QUANTIFICATION

A myriad of sources contribute to the uncertainty of an emission inventory. Whether at the national, entity, or facility level, the ability to quantify emissions and understand their associated uncertainty hinges on two main factors:

- readily available data for emission quantification; and
- knowledge of input parameters for statistical calculation of uncertainty.

The overall range of uncertainty associated with an entity GHG inventory is primarily determined by the uncertainty associated with the largest ("key") sources of emissions. These key emission sources differ by industry sector and characteristics of company operations[1]. Although very large confidence intervals may be associated with the data used to characterize some small sources, the overall impact on the range of uncertainty at the entity, or installation level, may often be very small. In turn, the confidence interval associated with each individual source depends on the availability of sufficient data to estimate emissions, or on the quality of the data in order to properly account for emission variability.

SECTION FOCUS

This section discusses the major sources affecting the uncertainty of GHG inventories. It moves from general concepts to issues that are germane to GHG inventories in the petroleum and natural gas industry. It also describes factors that could introduce errors into the emission measurements process and contribute to the range of uncertainties of estimated emissions.

The subsections address:

- Overview of emissions inventory uncertainty;
- Sources of Measurement Uncertainty;
- Emission Calculation Approaches;
- Inventory Steps and Data Aggregation; and
- Emissions Inventory and Uncertainty Assessment in the Petroleum and Natural Gas Industry.

2.1 Overview of emissions inventory uncertainty

Inventory uncertainties are largely dependent on the quality of available data. For determining the uncertainty ranges one has to evaluate three error categories:

a. *Spurious errors:* May be due to incomplete, unclear, or faulty definitions of emission sources that result from human error or machine malfunction.

a. *Systematic errors:* May be due to the methods (or models) used to quantify emissions for the process under consideration.

a. *Random errors:* May be due to natural variability of the process that produces the emissions.

Uncertainties might be associated with one or more factors such as: sampling, measuring, incomplete reference data, or inconclusive expert judgment. Uncertainties associated with inventories of emissions from known sources can be broadly categorized into scientific uncertainty and estimation uncertainty. Scientific uncertainty is a function of understanding the science of the actual emission and/or removal process. Estimation uncertainty--the main subject of this document--can be further classified into model (mathematical equation) uncertainty and parameter uncertainty. Model uncertainty refers to the uncertainty associated with the mathematical equations (i.e., models) used to characterize the relationships between various parameters and emission processes. Parameter uncertainty refers to the uncertainty associated with quantifying the parameters used for the calculations (e.g., activity data, emission factors or other parameters).

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[1] Emissions inventory examples are provided in Chapter 8 of the API *Compendium of Greenhouse Gas Emission Methodologies for the Oil and Natural Gas Industry* (API, 2009) and the relative uncertainty of the various sources is addressed in Appendices G and H of this document.

Uncertainties due to models (or equations) depend on the proper application of quantification methods for the respective source categories. These errors typically can be eliminated as far as possible in advance, when planning the compilation of an emissions inventory, and are often addressed as part of emission inventory assurance processes (API/IPIECA/OGP, 2011).

Parameter uncertainties can be evaluated through statistical analysis, measurement equipment precision determinations, and a variety of expert judgment techniques. Quantifying parameter uncertainties, and then estimating source category uncertainties based on these parameter uncertainties, is the focus of this document. Hence, adhering to appropriate sampling, measurement and estimation procedures – with applicable quality control and quality assurance measures – are all part of a quality improvement management system and can help minimize uncertainties.

Uncertainty estimates are tools that enable the inventory preparer to assess the major contributing factors to the emissions inventory and target the most significant ones, i.e., those exhibiting the largest range of uncertainty for more research and refinement. Table 2-1 provides an overview of selected methods recommended by the U.S. Environmental Protection Agency (EPA) for qualitative and quantitative estimation of the ranges of uncertainty for emissions. The uncertainties associated with natural variability inherent to the emission process and its underlying data can be assessed by the statistical analysis methods introduced in Section 5 and discussed further in Appendix F.

If measured parameters uncertainties are unknown, a pedigree matrix approach can be used to calculate uncertainties. In this approach, which is a method for structuring the expert judgment, qualitative data quality assessment results are used to relate data quality indicators to uncertainty ranges for individual parameters (WRI/WBCSD a, 2011).

Table 2-1. Overview of methods used to estimate emissions uncertainty[a]

Methodology	Description Of Method	Level Of Effort
Qualitative Discussion	– Sources of uncertainty are listed and discussed. – General direction of bias and relative magnitude of imprecision are given if known.	Low
Subjective Data Quality Ratings	– Subjective rankings based on professional judgment are assigned to each emission factor or parameter.	Low
Data Attribute Rating System (DARS)	– Numerical values representing relative uncertainty are assigned through objective methods.	Medium
Expert Estimation Method	– Experts estimate emission distribution parameters (i.e. mean, standard deviation, and distribution type). – Simple analytical and graphical techniques are then used to estimate confidence limits from the assumed distributional data. – In the Delphi method, expert judgment is used to estimate uncertainty directly. – In the Pedigree Matrix method, experts are used to set up the appropriate matrix for estimating data quality	Medium
Propagation of Errors Method	– Emission parameter means and standard deviations are estimated using expert judgment, measurements or other methods. – Standard statistical techniques of error propagation typically based upon Taylor's series expansions are then used to estimate the composite uncertainty.	Medium
Direct Simulation Method	– Monte Carlo, Latin hypercube, bootstrap (resampling), and other numerical methods are used to estimate directly the central value and confidence intervals of individual emission estimates. – In the Monte Carlo method, expert judgment is used to estimate the values of the distribution parameters prior to performance of the Monte Carlo simulation. – Other methods require no such assumptions.	High
Direct or Indirect Measurement (Validation) Method	– Direct or indirect field measurements of emissions are used to compute emissions and emissions uncertainty directly. – Methods include direct measurement such as stack sampling and indirect measurement such as tracer studies. – These methods also provide data for validating emission estimates and emission models.	High

[a] Extracted from Table 4.1-1 of the Emissions Inventory Improvement Program (EIIP), Chapter IV: "Evaluating the Uncertainties of Emission Estimates," EPA, Research Triangle Park, NC, July 1996

Expert judgment on methodology selection and choice of input data is the basis of all inventory development. When developing an emissions inventory, the goal of expert judgment is to ensure:

- choice of the proper methodology;
- selection of applicable emission factors and their uncertainty from ranges;
- identification of the use of relevant activity data;
- formulation of the most appropriate way to apply a given methodology; and
- determination of the appropriate mix of technologies represented.

In the pedigree matrix approach, data sources may be assessed according to five data quality indicators, which comprise precision and completeness, along with three representativeness considerations (temporal, geographical, and technological). Each of these indicators is assigned one of four data quality criteria (very good, good, fair, and poor). Exhibit 2-1 describes the five data quality indicators that are useful for assessing the uncertainty of emission inventories.

Further discussion on the use of the Pedigree Matrix approach and an example application for petroleum and natural gas greenhouse gas inventories are provided in Sections 5.1.3 and 5.3.2, respectively.

EXHIBIT 2-1: DATA QUALITY INDICATORS

- **Precision** – relates to the repeatability of measurements as defined by the error estimate or the spread of the measurements cluster.
- **Completeness** – relates to the statistical properties of the data: how representative is the sample, does the sample include a sufficient number of data points and is the period adequate to even out normal fluctuations. Completeness relates to the properties of the sample itself.
- **Temporal Representativeness** – relates to the time correlation between the year of data collection and the inventory year. This is an essential consideration for industry segments with rapid technology development, which might cause the emissions and the production efficiency to be totally changed.
- **Geographical Representativeness** – relates to the spatial match between the area where data are collected and the area included in the inventory.
- **Technological Representativeness** – relates to the correlation of the data used in the inventory to the data of the specific entity, processes, and materials that lead to emissions.

2.2 Sources of measurement uncertainty

The measurement process is comprised of different steps and each can introduce uncertainty into the final results, where each of these steps may be associated with either activities or emission factors.

The sources of uncertainty summarized in Table 2-2 range from methods choice to physical constraints of the measurement process itself. Uncertainty may also be introduced due to errors in the processing of collected data such as operating conditions or other constants used for the calculation. Similarly, they may be due to spatial or profile uncertainty when using distinct measurements to represent similar processes at different times and locations.

2.3 Emission calculation approaches

Emissions information typically is obtained either through direct on-site emission measurements, or by using engineering emission techniques that are based on appropriate equations, models, or emission factors that describe the physical process. Emission estimates are used for facility permitting, development of control strategies, compliance review, and demonstration of attainment of environmental goals.

Table 2-2. Summary of typical sources of measurement uncertainty

Sources of Uncertainty	**Description**
Measurement methods	Some common sources of measurement system uncertainties include: – Improper placement of monitoring device or extraction of unrepresentative samples. – Environmental effects on measurement instruments, such as heat transfer effects on a temperature probe, or pressure considerations for flow measurements. – Drift of an instrument between successive calibrations. – Electrical interference with electronic components. – Variation between the calibration and usage conditions.
Calibration	Measurement instruments are typically calibrated before they are used in the field or in a plant: – Instrument calibration needs to be checked periodically to detect instrument drift and reduce measurement uncertainty. – The calibration process ought to be traceable to a known reference standard. – Allowance should be made for adjustments of the measurement instrument if a bias is detected during the calibration process.
Data acquisition	Uncertainties in data acquisition systems depend on system design: – For manual data collection, and more specifically data entry, human error can be a factor. – If hard copy data are used, misplaced records could contribute to uncertainty. – For instrumental data acquisition, uncertainty can arise from the signal conditioning, and the sensors or recording devices used.
Data Processing	Uncertainty in data processing may be attributable to multiple sources: – Model equations for simulating process emissions may be oversimplified and not adhere to physical realities. – Coefficients of regression for instrument calibration indicate scatter of the measurement data. – Use of non-uniform sets of conditions and improper unit conversions, introduce bias to the calculated values. – Improper uploading of electronic data may introduce bias.
Data Quality	Quality control techniques and robust data management practices can minimize the effects of many sources of uncertainty: – Comparing known input values with their measured or computed results can provide an estimate of the data acquisition uncertainty. – When it is not possible to do this in practice, it is advisable to evaluate potential individual and aggregated errors when assessing uncertainty.

The general equation for quantifying emissions is:

Emissions = Activity Rate × Emission (conversion) Factor *(Equation 2-1)*

When calculating emissions and their associated uncertainties, it is important to note that the overall uncertainty is based both on the variability associated with the activity data (process flow, throughput, usage or equipment count) and on the accuracy of the emission factors used.

In practice, for estimating GHG emissions from the oil and natural gas industry this means:

- *For CO_2 (combustion)*

Emissions = Volumetric Gas Flow × Carbon Composition × Combustion Efficiency *(Equation 2-2)*

– or –

Emissions = Fuel Energy Consumption × Carbon per Heating Value Unit × Combustion Efficiency *(Equation 2-3)*

- *For CH_4 (non-combustion)*

Emissions = Component or Event Count × Emissions (Conversion) Factor *(Equation 2-4)*

The four basic approaches for estimating emissions and their potential error sources are summarized in Table 2-3. Each contributor to uncertainty should be assessed independently and then aggregated in the final analysis, as discussed below.

In the absence of direct emission measurements, the use of emission factors has traditionally been the simple, low cost method of choice for estimating emissions. Over the years, the EPA and other emission factor repository databases have provided average emission factors that can be used broadly across many industry source categories and operations. The published emission factors are typically accompanied by a description of the group of processes and the conditions they represent. Authoritative factors are generally published by the EPA in AP-42 (EPA, 1995 and further updates), or by the EU EMEP/CORINAIR Emission Inventory Guidebook (EEA, 2013). The IPCC has also launched a new Emissions Factors Database (IPCC, EFDB) for use with GHG emission calculations.

Table 2-3. Common emission estimation approaches and their error sources

Emissions Estimation Approach	Description
Emissions Factors	An emission factor relates the rate of emission of a specific compound to an activity rate associated with its release. The errors associated with the use of emissions factors are attributed to: - Variations in operating conditions during the collection of emission and activity data that were used in the development of the emission factors. - Variability in emissions that arises from differences in operating conditions among different facilities where the factors are used. - Difference between the actual composition of the stream to which the emission factor is applied and the default composition on which the emission factor is based. - Uncertainty that is due to measurement errors, systematic errors, and random sampling errors.
Continuous Emissions Monitoring System (CEMS)	The technique involves continuously measuring flow and concentrations of species directly emitted into the atmosphere from a specific source, such as a stack. It is accomplished by placing applicable monitors at the source. Uncertainty associated with CEMS generally includes: - Stack flow measurements. - Concentration measurements. - Measurements of stack temperature and pressure required to correct emissions to standard conditions. The error associated with these determinations varies for different compounds. CEMS will not necessarily produce emission estimates with lower uncertainties than alternative methods especially since CEMS are not available for monitoring all GHG emissions. CEMS may not be practical for a large number of emission sources.
Source Testing	This technique involves either extracting a sample or placing a monitor at a source, followed by analysis to characterize the emitted species. The measurement campaign is typically limited to a specified number of hours, and the average emission rates calculated are used to estimate total annual emissions. For characterizing GHG emissions over a longer period of time (such as a year), periodic sampling and analysis can be used to determine emission variability. The errors associated with these measurements are due to: - Sporadic testing of limited duration that is used and extrapolated to characterize emissions over a longer period, i.e., a year, not allowing for a robust estimate of variability. - Testing methods used are either improperly calibrated or do not have Version 2, September 2014 2-7 sufficient sensitivity to enable characterization of the full gamut of emission rates.
Material Balance	This technique is based on the material balance or total quantity of material used, e.g., fuel flow into a combustion device and its carbon speciation. The errors associated with this method include: - Improper calibration and measurement of applicable flow devices. - Inaccurate determination of material stream composition.

2.4 Inventory steps and data aggregation

When developing GHG emission inventories, emission estimates are obtained from many intermediate and independent results, each of which is calculated from a separate set of data that is characterized by a different range of uncertainties. The compilation of an entity-wide GHG emissions inventory typically follows a sequence of steps:

a. **Establishing boundaries** – Where the organizational and operational boundaries are defined (for a first-time inventory), or examined (for recurring cycles), this step will be largely dictated by local requirements or corporate policies. It might involve facility-by-facility assessment prior to aggregation, or it could use other pertinent entity indicators and information.

b. **Collecting and inputting data** – Where the activity data are collected and archived based on the boundaries established above. The data are then incorporated into appropriate calculation tools for emission calculations. The level of 'granularity' of the data collected and the details of the calculation methods are dictated by local requirements with industry guidance (API *Compendium*) as a resource to provide relevant technical details.

c. **Validating data compiled** – Where various techniques are used to compare the new data with earlier versions (if available) to identify potential large errors. These errors could include: either large changes or unchanged activity data for given facilities; operations that are not accounted for; lack of supporting data for measurements or emission factors used; erroneous units or unit conversions among others.

d. **Assessing data uncertainty** – Where the confidence intervals associated with the data available for each of the emission sources are characterized independently, as discussed later in this document. The uncertainty information could be based on documentation of data repositories (API, 2009), expert judgment, or on measurements conducted during the inventory year.

e. **Finalizing the inventory** – Where the quality-checked and validated data are aggregated for reporting based on company policy or local requirements. The preferable way of reporting the results is in terms of the total emissions for each of the GHG species, along with the global warming potential-weighted sum of these emissions (also known as the CO_2e emission).

The overall uncertainty range for each GHG species, and CO_2e, should also be reported with the total emissions in the format of:

Emissions = Average Value ± %
(at the 95% confidence limit).

(Equation 2-5)

2.5 Emissions inventory and uncertainty assessment in the petroleum and natural gas industry

Inventorying of GHG emissions by entities is a 'bottom-up' summation of emissions from individual sources (or emissions from the total consumption of different fuel types) at a reporting unit to create an inventory for that reporting unit. Emissions from disparate reporting units may be aggregated to create an entity, or corporate, inventory. Reporting units may be defined by the reporting entity to represent logical groupings of activities and assets, or could be mandated by governments as part of GHG reporting regulations. Developing these GHG inventories entails both the proper accounting of activity levels for operations that may lead to GHG emissions as well as the conversion of these activity levels to quantitative GHG emissions using proper measurement and calculation methods.

The petroleum and natural gas industry encompasses a wide variety of activities, ranging from the exploration and production of petroleum and natural gas to the delivery of products to consumers. As part of defining the scope of GHG inventories, industry guidelines (IPIECA/API/OGP, 2011) are available to assist companies in determining which emissions related to their activities should be included within the organizational boundaries they have established. In all cases, mandatory GHG reporting requirements would take precedence over industry guidelines, as may be the case in different jurisdictions.

For a complex and dynamic sector such as the oil and natural gas industry, a variety of methods are applicable to quantifying GHG emissions, ranging from simple activity measurements multiplied by applicable emission factors to more sophisticated quantification algorithms. Advanced engineering estimation methods consist of an integrated approach that relies on the use of emissions and physical activity factors in conjunction with generic process simulation models, source-specific models, and species profiles databases. Each of these estimation methods will have a different level of uncertainty. For example, combustion emissions are dependent on the amount of fuel consumed. This can be estimated based on the hours of equipment operation, equipment rating, and thermal efficiency. The uncertainty associated with this approach differs from the uncertainty associated with directly measuring fuel use.

Selection of an appropriate emission estimation method must consider:

- The objectives of the emission inventory;
- The contribution of the emission source to the overall accuracy of the emission inventory; and
- The costs and practicality of the emission estimation method.

Figure 2-1 provides a general hierarchy of accuracy associated with common emission estimation approaches. Accuracy is generally improved as emission estimation progresses from default emission factors to more direct estimation or measurement methods. For example, measuring CH_4 and CO_2 emissions from every dehydrator in a natural gas production field may produce a highly accurate emission rate, but at great expense for a source that has minimal contribution to the GHG inventory of the field and can be estimated using an engineering modeling approach, such as GLYCalc™ (GTI, 2000).

Figure 2-1. Hierarchy of emission estimation approaches

Types of Approaches	**Hierarchy**
Published emission factors	 **Improved accuracy** **Additional data requirements** **Higher cost**
Equipment manufacturer emission factors	
Engineering calculations	
Monitoring over a range of conditions and deriving emission factors	
Periodic monitoring of emissions or parameters for calculating emissions	
Continuous emissions* or parameters monitoring	

*Continuous emissions monitoring may not be directly applicable to certain greenhouse gases or to all emission sources.

The third edition of the API *Compendium* (API, 2009) provides an extensive compilation and tabulation of methods used by companies in all segments of the petroleum and natural gas industry for consistent calculation of GHG emissions. The API Compendium provides a wide range of emission factors and other emission estimation methods that are directly applicable to all sectors of industry operations. Summary tables and decision trees are provided to illustrate the variety of available emission estimation options and the associated considerations. It also lists the uncertainty ranges (at the 95% confidence level) associated with multiple case study examples featured in Section 8 of the 2009 API *Compendium*.

Related industry guidelines include those of the Interstate Natural Gas Association of America (INGAA), which provides supplemental guidance for estimating GHG emissions from key emission sources associated with the natural gas storage and transmission sector of the industry (INGAA, 2005) and the American Gas Association (AGA), which has also published specific guidelines for estimating GHG emissions from gas distribution operations (AGA, 2008).

Industry guidelines also served as major input to the formulation of regulations governing the mandatory reporting of GHG, such as the U.S. GHG Reporting Program (EPA, 2009), the Western Climate Initiative (WCI, 2009), and the California Air Resources Board (CARB, 2012).

The categories of sources that contribute to overall GHG emissions as classified in the API Compendium (API, 2009) are:

- ***Stationary combustion sources*** – linked to emissions resulting from the combustion of fuels in boilers, furnaces, burners, heaters, and stationary turbines and engines. This category may also include the combustion of waste gases-or emergency releases-in incinerators and flares.
- ***Mobile combustion sources*** – linked to emissions resulting from combustion of fuels in ships, barges, trains, trucks, automobiles, aircrafts and other off-road devices such as drilling rigs.

- ***Process Vents*** – linked to the emissions that result from physical or chemical processing of materials within the petroleum industry. The materials may include both gaseous and liquid hydrocarbon streams that contribute to both CO_2 and CH_4 emissions.
- ***Equipment Leaks*** – linked to leakage from piping components such as from seals, gaskets, valves, packing rods, emergency relief devices and similar items.

It is important to note that under global practices adopted by the IPCC for national GHG inventories, the aggregate of all non-combustion emissions are referred to as "fugitive emissions." Under those practices, even flares are included within the "fugitive emissions" category. Confusion might arise since under the U.S. Clean Air Act the term "fugitive emissions" refers to equipment leaks only, while the U.S. GHG Inventory adheres to the IPCC format and its broader definition of "fugitive emissions".

Industry operations vary widely among operating segments due to the nature of the operations, their geographical locations and local practices. Operations in some of the industry segments are highly centralized in large and complex facilities while in others they extend over large geographical areas, with some of the operations not contained in traditional "facilities". Additionally, company operations tend to encompass many jurisdictions, which add to the complexity of compiling an emission inventory, even for a given corporate entity. Data availability may be different among industry segments and operating regions due to an operational considerations and local requirements.

The uncertainty associated with quantifying CO_2 emissions from combustion would be primarily attributable to variation in the composition of combusted fuels and their respective consumption rates (or total volumes). For quantification of combustion emissions, quality data are typically available for industry facilities in all segments, though significant effort may be required to collect data for smaller operating installations that are geographically dispersed.

Since a large fraction of industry operations rely on self-generated fuels, it is the knowledge of the carbon content – or heating values – of such fuels that is at the root of determining their associated CO_2 emissions. For the exploration and production segment, the composition of these self-generated fuels vary with the nature of the producing formations, while for refining it depends on the composition of the feed slate and the diversity of refinery process units that determine the products manufactured. On the other hand, for natural gas transmission and distribution operations, gas quality and its composition are expected to adhere to contract requirements and would vary only within a narrow specifications range. Hence, the use of average fuel compositions data has to be evaluated when compiling an emission inventory since it might result in wide uncertainty ranges for some segments and operations, while it might be perfectly acceptable for others.

A different set of parameters is important for understanding emissions associated with process vents and fugitive emissions due to equipment leaks. For many of the large process units in refineries and natural gas processing plants, numerical models (equations) are available for estimating these emissions. For high-pressure pipelines transmitting natural gas over long distances, the main GHG emissions are due to reciprocating compressor engines and turbines, venting due to gas blow-down, and fugitive emissions associated with leaking piping components. For low-pressure gas distribution, most of the GHG emissions result from compressors and leaks from gas distribution mains and associated equipment.

Quantifying emissions, and their associated uncertainty ranges, for venting and equipment leaks in the exploration and production segment poses a real challenge. These emissions vary widely in magnitude depending on the characteristics of the producing formation but they are generally attributable to workover and completions, gas well liquids unloading, venting from pneumatic controllers, flashing from condensate and oil storage tanks and more.

Operators in the USA, as well as in other jurisdictions, maintain required records for reporting (and archiving) inadvertent gas-venting incidents. USA reports of "lost and unaccounted for gas" from natural gas pipelines account for both vented and fugitive emissions, as well as metering errors. Therefore, it will be necessary to disaggregate the data in order to derive a separate average emission factor for venting incidents only. When it comes to fugitive emissions from equipment leaks, the uncertainty associated with current practices is significant. The most reliable emission factors still use mid-1990 field measurement data and, when coupled with the difficulties of obtaining reliable equipment counts for estimating such emissions, the result could exhibit large uncertainty ranges, although these emissions may be negligible within the context of the overall inventory.

In summary, since the most prevalent gas emitted from fuel combustion is CO_2, and from venting and fugitive emissions, CH_4, the main contributors to the uncertainty ranges of these respective GHGs in an inventory generally are:

- ***For estimating CO_2 emissions from combustion*** – Uncertainty is primarily attributable to variation in "self-generated" fuel gas composition and its associated consumption rates. Fuel gas composition could vary from location to location or from batch to batch, and therefore using average composition data may lead to a high degree of uncertainty if it is used to estimate emissions. Measurements (or knowledge) of fuel gas volumes, the gas carbon content (or calorific values), and careful review of the adequacy of the emission factors used could help to improve data quality and minimize this uncertainty.
- ***For estimating CH_4 emissions*** – Uncertainty is primarily associated with estimates of vented and fugitive emissions. The frequency of venting and its duration under normal operations, along with the methane content of the emitted gas, is just now starting to be measured or estimated routinely in some jurisdictions (e.g., GHGRP, 2010). For inadvertent venting and methane releases, there is no uniformity of record-keeping requirements under all regimes globally. Fugitive emission estimates exhibit the highest degree of uncertainty due to the use of average emission factors per component, device, or type of operation. Uncertainty is also introduced by improper conversions of existing factors that are expressed in terms of volatile organic compounds (VOCs) to CH_4. Since the CH_4 to VOC ratio varies among installations, or even within different parts of a processing plant, these average emission factors, coupled with generic conversions from VOC to CH_4 , may not be the best representation of CH_4 emissions.

3. OVERVIEW OF MEASUREMENT PRACTICES FOR ESTIMATING GREENHOUSE GAS EMISSIONS

In defining aggregated uncertainty of measurement ensembles used for developing emission inventories, the uncertainty for each measurement stream must be assessed in a way that is applicable to that measurement method and its implementation in practice. Random errors could be a major factor in the uncertainty of an individual observation; however, their contribution to the overall emission inventory diminishes as more measurements are obtained during the reporting period.

Note: Random errors tend to average out during the year, whereas systematic errors (or measurement bias) become more important and tend to accumulate rather than diminish over longer periods of time such as a year.

In fact, determining the true value of any measured variable is not practical due to the limitations of measurement equipment and procedures, and the possibility of human error. Hence, industry measurement procedures and standards have been developed to emphasize practices that lead to collecting better quality data, especially for critical measurements. Industry uses standards from several different standards-developing organizations, resulting in equivalent measurements, based on the scope of the standard, company preference, and type of devices used. Consensus industry standards, such as those developed by ANSI, API, ASTM, ISO and other standard-setting organizations, have rigor in their development process, and measurement standards are reviewed at least every five years to ensure that standards are in step with technological changes and advancements. Most, if not all, of the measurement standards are developed for measurements associated with 'custody transfer' and to define quantities that are essential for robust financial transactions.

API publishes one of the more comprehensive sets of custody transfer measurement standards, but it is neither complete nor the only widely recognized source for such industry practices. API's MPMS (*Manual of Petroleum Measurement Standards*) includes over 140 titles, and API publishes approximately eight new or revised measurement standards each year. Appendix B presents a comprehensive list of specific measurement standards (and their respective editions) from several standards-setting organizations, which could be used to support the calculation of GHG emissions. It is up to the user of these measurement standards to reference the specific standards/editions used for a given measurement, and to incorporate the updated measurement procedures, as applicable.

Custody transfer measurements are typically are expected to meet a set of performance specifications. For other measurements, such as those performed to support the development of a GHG emissions inventory, data quality objectives should be established prior to initiating any data collection to ensure that the uncertainty ranges of the measured quantities are consistent with the intended use of the data. Throughout this section, we provide references and describe

SECTION FOCUS

This section provides an overview of measurement practices focusing on gas flow measurements and the determination of carbon content or the heating values of combusted fuels. The section recognizes industry-recommended practices and standards including those that traditionally applied to "custody transfer" of fuel products and new ones that have been more recently developed for use in an emissions estimation context.

This section goes on to link these practices to the acquisition of GHG emissions and related activity data, representing a move from reliance on available data or engineering judgment. The subsections address:

- Flow Measurement Practices;
- Flow Measurements for GHG Inventories;
- Sampling and Analysis for Quantifying GHG Emissions;
- Carbon Content Measurement Practices;
- Heat Content Determination;
- Venting and Fugitive Emissions Measurements; and
- Laboratory Management System.

a select subset of industry standards that are most typically used for the respective measurements discussed. Even so, the full list of measurement methods provided in Appendix B could be used to provide equivalent measurements to meet company practices and available instrumentation.

For many petroleum and natural gas industry installations, CO_2 emissions from combustion and flaring are the largest contributors to overall GHG emissions. Therefore, this section focuses on measurements and methods typically used for quantification of these CO_2 emissions. The subsections below provide details on flow measurement practices, and their associated uncertainties, as well as methods for the measurement of carbon content and heating values of combusted fuels.

For some other petroleum and natural gas industry sectors, such as exploration, production, processing, transmission and distribution operations, emissions from other GHGs (such as methane) can contribute significantly to a facility's GHG emissions. Available emission factors exhibit large uncertainties and might not be representative of current operating practices. Therefore, for inventories where CH_4 constitutes a larger fraction of the emissions, the overall uncertainty would be expected to be substantially higher.

Industry is now more fully internalizing the potential impact of measurement errors and bias through the full chain of emission calculations including measurement equipment, software calculations, simulation models, and the limitations of reliance on existing emission factors on the uncertainty range of resultant GHG emissions inventories. Considerations of the need for more representative measurement data, and the assessment of equipment design and age, are gaining more prominence in the process of assembling high certainty emission inventories. This section focuses on measurements that are pertinent to improved characterization of combusted fuels and the quantities used, but might not be directly applicable to measurement of leakages and fugitive emissions. The measurement practices highlighted here represent an initial step in what could end up being a multi-year effort to improve measurements of GHGs and quantify the activities that cause their emissions.

3.1 Flow measurement practices

Continuous handling of very large liquid and gas flow volumes is a characteristic of all the sectors of the petroleum and natural gas industry. Therefore, an in-depth understanding of flow measurement is essential both for internal process control and for transferring "custody" of intermediate streams or finished products. The measurement accuracy of "custody meters" is historically quite high, and practices follow rigorous industry standards.

Industry has been instrumental in developing international voluntary standards such as ISO 5168:2005 (ISO, 2005) establishing general principles and describing procedures for evaluating the uncertainty of measuring fluid flow rate or quantity. Annex A of ISO 5168 provides a step-by-step procedure for calculating and reporting these measurement uncertainties. Similarly, Chapter 14 of the API *Manual of Petroleum Measurement Standards* (MPMS), contains detailed procedures and practices for all aspects of natural gas (and similar gases) fluids measurement and calculation of their associated uncertainties, at the point where oil or gas enters the marketplace ("custody transfer") (API a, 2006). Those same practices are not as rigorously applied to internal accounting and process control during normal operations.

3.1.1 Measurements by Orifice Meters

Orifice meters are by far the most prevalent flow meter type used in the petroleum and natural gas industry, and are used for metering products during "custody transfer" as well as for process control and internal accounting. These flow meters are also used to account for fuel volumes when estimating CO_2 emissions. Flow meters are designed for long-term reliability and ruggedness under a variety of component mixtures and conditions that are essential for consistent fluid blending and processing. Although for this type of meter, temperature and pressure calibrations can be done while the units are operating; they generally have limited access to direct orifice plate inspections and maintenance outside of planned shutdown ('turnaround') cycles.

Recommended practices for the installation, calibration, and calculation of flows for these custody meters are provided in Section 3 of Chapter 14 of API's MPMS (API, 2013). This standard was developed through a collaborative effort by members of API, AGA, and the Processing Gas Association, with contributions from the Canadian Gas Association, American Chemistry Council, the European Union, Norway, Japan, and others. It is designed to ensure global consistency for petroleum and natural gas transactions and is recognized by the Version 2, September 2014 3-3

American National Standards Institute (ANSI) as an American National Standard. The four-part standard for square-edged, concentric orifice meters consists of:

- **Part 1:** General equations and uncertainty guidelines.
- **Part 2**:Specifications and installation requirements;
- **Part 3**: Natural gas applications.
- **Part 4:** Background, development, implementation procedures, and subroutine documentation.The standard recognizes that many factors contribute to overall measurement uncertainty associated with many metering applications, as summarized in Exibit 3-1

EXHIBIT 3-1: FACTORS CONTRIBUTING TO MEASUREMENT UNCERTAINTY FOR ORIFICE METERS

a) Tolerances in prediction of coefficient of discharge

- Derivation of the basic flow equation for an orifice flowmeter is based on physical laws.
- Any derivation is accurate when all assumptions used to develop the equation are valid.
- The empirical equation for the coefficient of discharge that is included in API 14.3 was developed from a large database with well-controlled and quantified independent variables.

b) Predictability in defining the physical properties of the flowing fluid

- All empirical equations and standards for concentric, square-edged orifice meters apply to steady state flow conditions for fluids that are considered to be clean, single phase, and homogeneous, such as all gases – and most liquids – in the petroleum, petrochemical, and natural gas industries.
- Fluid’s flow rates are expressed in volume units at base (standard or reference) conditions, and the volumetric flow rates that are measured at the operating flowing conditions are then converted to standard volume with respect to the base conditions.
- Fluid properties are defined as a function of the operating pressure and temperature that are monitored by secondary devices. Significant temperature variation between the thermal well and the orifice taps will affect the measurement.

c) Fluid flow conditions

- A database is available for the empirical equations for coefficient of discharge for steady-state fully developed pipe flow profile with negligible or no swirl flows and flow fluctuations.
- Deviations from these conditions typically are due to piping installation upstream of the flowmeter and they introduce flow measurement uncertainty.

d) Construction tolerances in meter components

- Part 2 of the reapproved API MPMS Chapter 14.3 standard lists the changes recommended in the mechanical tolerance requirements for the orifice meter components.
- The standard encompasses a wide range of diameter ratios for which experimental results are available and some of the tolerances are more stringent than the tolerances in the previous standards.

e) Uncertainty of secondary devices/instrumentation

- The secondary devices are the instruments used to monitor the flowing fluid temperature, pressure, and the differential pressure across the orifice plate.
- Parameters affecting the accuracy of the differential pressure device include: ambient temperature, static pressure, linearity, repeatability, long-term stability, and drift, as well as the uncertainty of the calibration standard.
- The stated accuracy of most differential pressure-measuring devices is expressed as a percentage of the full-scale reading, which leads to increased error bands with decreasing differential pressures.

f) Data reduction and computation

- Ultimate errors in flow rate computation depend on the accuracy of defining the physical properties of the flowing fluid, as computed by the microprocessor-based flow computers.
- Computation of the physical properties, especially for gas flows, is dependent on the constituents of gas in the flowing fluid.
- All fixed input and critical parameters affecting the flow rate computation should be verified to reduce bias error in flow measurement.

All these factors should be assessed when estimating the overall range of uncertainty for flow measurements using thin plate, concentric, square-edged metering systems.

In the reapproved 2012 version of the standard, several changes were incorporated to reduce the uncertainty attributable to installation effects and to improve the rigor of the flow calculation routines. The revised standard recognizes the lead time necessary for upgrading existing installations, and leaves this lead time to the discretion of facility operators and their data quality targets for flow measurement data.

However, it should be recognized that if orifice meter installations are not upgraded to conform to the new recommendations, measurement bias error may occur. This bias might be due to improper upper and lower distances from bends and points of flow turbulence that might lead to inadequate flow conditioning prior to measurement. Additionally, even without changing equipment installations, the standard recommends adopting new calculation procedures and techniques (explained in Part 1 and 3 of the standard) that represent significant improvements over the previously adopted approach. It is important to note that the expected uncertainty ranges for flow measurements quoted in Part 1 of the reaffirmed standard may differ from those obtained in practice when the equipment installation differs.

3.1.2. Measurement of flow to flares

The measurement of flow to flares is distinctly different than other flow measurements. Flares are designed as safety relief systems and typically are capable of handling highly variable flow rates of widely varying gas compositions. Therefore, some of the practices that are generally applicable to custody transfer or process control flows have to be modified when addressing flows to flares. API published a measurement standard addressing gas or vapour flare flow measurements, which also includes cautionary details about the effects of fouling (due to entrained liquid droplets, aerosol mists, or other contamination) on the measurement (API MPMS, July 2007).

Most flare headers are designed to operate during both non-upset conditions at near atmospheric pressure and ambient temperature, and during flare episodes, at a wide range of pressure, temperature, and flow velocities. During such episodes, flare gas compositions are also highly variable and could range from molecular weights approaching that of hydrogen to molecular weights of C5+.

As with other flow measurements, the accurate determination of flow to flares is dependent on many parameters such as the ability to predict – or measure – the quantity of gas flared, mixture composition, pressure, temperature, and/or density. For example, gas-to-oil ratio (GOR) measurements can be used to estimate the volume of gas flared for isolated oil production operations, or engineering estimates based on purge rates or operating logs can be used to estimate flare volumes for refineries or gas plants.

The accuracy of measurements associated with highly variable flare gas mixtures will depend largely on the meter technology type and the ability of the flare flow measurement system (FFMS) to achieve the targeted response time and analytical accuracy levels. Exhibit 3-2 below lists the basic steps needed to conduct a simplified analysis for determining the uncertainty ranges of a given flow measurement system. The actual approaches for the required calculations are provided in Section 5, and Appendix F provides examples demonstrating how to apply these methods.

EXHIBIT 3-2: STEPS FOR SIMPLIFIED UNCERTAINTY ANALYSIS

a) Determination of the equation that defines the meter output

- Governing equations are those applicable for the meter technology type used.

b) Determination of the combined sensitivity coefficient

- Numerical values of uncertainty are associated with pressure, temperature, and composition.
- Meter accuracy is estimated from calibration data, pipe size, or other installation effects.
- Sensitivity coefficients are obtained by dividing the calculated percent uncertainty for an input variable by the percent change in that input variable.

c) Derive the combined uncertainty range (extended standard deviation)

- Combined uncertainty is calculated by summing the square of the errors for pressure, temperature, composition, meter calibration, and installation effects.

Variability in flare composition may also be a significant factor in determining the measurement uncertainty of an FFMS. Knowledge of flare composition may have a major effect on the calculation of the actual volume, standard volume, or mass measured by the meters. For example:

- **For a differential pressure meter**: the output is a function of the square root of the flare gas density.
- **For thermal flow meters:** knowledge of the actual volume (or standard volume) requires consideration of the compositional effect on thermal conductivity and dynamic viscosity.
- **For ultrasonic flow meters**: sound speed is a function of gas composition.

Converting volume flow to mass flow requires knowledge of gas composition in order to derive gas density. When an analyzer is incorporated in the measurement system to correct for composition, care must be taken to ensure that the response time of the system is short compared to the upset flow event during flaring to ensure representative measurement during actual flaring.

An example of how all of these elements would be combined into the overall measurement uncertainty is provided in Table 3-1.

3.1.3 Flow measurements uncertainty analysis

The result of a measurement process is the determined quantity of the parameters measured. For flow measurements the quantities may include pressure, temperature and volumes, (i.e., multiple components) contribute to the accuracy, or uncertainty, of the final result.

Table 3-1. Example of flare flow measurement systems combined uncertainty [a]

Variable	Combined Sensitivity and Error (S x U95)	(S x U95)2
Pressure	2.0%	4.00
Temperature	0.1%	0.01
Flare Composition	2.0%	4.00
Meter error (calibration	1.4%	1.96
Installation effects	0.5%	0.25
Sum of squares		10.22
Square root of sum of square		3.2%

[a] Table 4 from API MPMS Section 14.10 (API, 2007)

Each component in the measurement system will exhibit variations that contribute to variations in the process result. Variability may be due to procedure(s), operator(s), environment, instrument(s) and maintenance. Consequently, repeated results from the same measurement process may vary, and there is always the potential that many small variations will affect the final results.

Therefore, it is advisable to analyze the overall uncertainty of the flow measurement process to affirm its adequacy for the intended application. As indicated in Exhibit 3-2, a few key steps should be followed to determine the combined uncertainty associated with individual flow measurements. An expanded discussion of factors to be considered when evaluating the uncertainty of flow measurements used for GHG emission calculations is included in Section 3.2.

3.1.4 Uncertainty specifications for "custody transfer" measurements

"Custody transfer" measurements are defined as measurements that provide quantity and quality information, which can be used as the basis for a change in ownership and/or a change in responsibility for materials. In most petroleum and natural gas producing jurisdictions around the world, national regulations and directives have emerged to specify requirements for the expected accuracy and uncertainty ranges associated with "custody transfer" and other critical measurements. For such precise metering applications, the flow meters and adjacent piping used in the measurement system are expected to meet the requirements of the relevant, preferably the most stringent, specifications of the API and ISO standards that are cited in many national regulations.

One such example of measurement requirements promulgated for petroleum and natural gas operations is Directive 017 of the Alberta Energy Regulator (AER, 2013), which spells out the measurement requirements for upstream oil and gas operations in Alberta, Canada:

- The standards are stated as "maximum uncertainty of monthly volume" and/or "single point measurement uncertainty," as listed in Table 3-2 below for petroleum (oil) Systems and Natural Gas Systems measurements, respectively.

Table 3-2. Summary of Alberta ERCB accuracy requirements[a]

		Maximum Uncertainty of Monthly Volume	Single Point Measurement Uncertainty
	PETROLEUM SYSTEMS MEASUREMENTS		
(i)	**Total battery oil (delivery point measurement)**		
	Delivery point measures >100 m^3/d	N/A	0.5%
	Delivery point measures < 100 m^3/d	N/A	1%
(ii)	**Total battery gas (includes produced gas that is vented, flared, or used as fuel)**		
	> 16.9 103 m^3/d	5%	3%
	> 0.50 103 m^3/d but < 16.9 103 m^3/d	10%	3%
	< 0.50 103 m^3/d	20%	10%
(iv)	**Well oil (proration battery)**		
	Class 1 (high), > 30 m^3/d	5%	2%
	Class 2 (medium), > 6 m^3/d but < 30 m^3/d	10%	2%
	Class 3 (low), > 2 m^3/d but < 6 m^3/d	20%	2%
	Class 4 (stripper), < 2 m^3/d	40%	2%
(v)	**Well gas (proration battery)**		
	> 16.9 103 m^3/d	5%	3%
	> 0.50 103 m^3/d but < 16.9 103 m^3/d	10%	3%
	< 0.50 103 m^3/d	20%	10%
	GAS SYSTEMS MEASUREMENTS		
(i)	**Gas deliveries (sales gas)**	N/A	2%
(ii)	**Hydrocarbon liquid deliveries**		
	Delivery point measures >100 m^3/d	N/A	0.5%
	Delivery point measures <100 m^3/d	N/A	1%
(iii)	**Plant inlet or total battery/group gas**	5%	3%
(iv)	**Plant inlet or total battery/group condensate (recombined)**	N/A	2%
(v)	**Fuel gas**		
	> 0.50 103 m^3/d	5%	3%
	< 0.50 103 m^3/d	20%	10%
(vi)	**Flare gas**	20%	5%
(vii)	**Acid gas before compression**	N/A	10%
	Acid gas after compression		3%
(viii)	**Dilution gas**	5%	3%
(ix)	**Well gas (well site separation)**		
	> 16.9 103 m^3/d	5%	3%
	< 16.9 103 m /d	10%	3%
(x)	**Well gas (proration battery)**	15%	3%
(xi)	**Well condensate (recombined)**	N/A	2%

[a]Note: Extracted from Section 1.8.1 and 1.8.2, respectively, ERCB Directive 017, September 2012

- The uncertainties are to be applied as "plus/minus" (e.g., ±5%), and only measurements at the delivery or sales points are required to meet the highest accuracy standards since they would have a direct impact on royalty determination.

The directive makes it clear that other measurement points that play a role in the overall control and accounting process would be subject to less stringent accuracy standards. These less stringent accuracy standards are designed to accommodate physical limitations and/or the overall economics of achieving very stringent accuracy standards for each volumetric measurement.specifications of the API and ISO standards that are cited in many national regulations.

3.2 Flow measurements for GHG inventories

Measuring gas or liquid flow rates, or their total volume for calculation of GHG emissions, requires that the flow meters used should be fit for purpose. They should be properly installed and calibrated, to ensure that they are capable of providing data that are within the uncertainty ranges required by the governing climate program. Consideration should be given to differences between the manufacturers' specifications of flow meters' expected measurement errors and those that are attained when using the flow meters in the field. It is common practice to test flow meters in a laboratory setting under controlled conditions prior to field installations. However, these laboratory bench tests typically do not simulate "real world" variations in fluid flow and other possible fluctuations, and drift of the entire measurement system. For any given operating facility, only a very limited number of "custody transfer" meters are equipped for field calibration under real operating conditions.

3.2.1 Flow meter types

As an example, Table 3-3 provides a listing of different meter types, their applicable fluid medium, and a brief description of their operating principles. The table also lists manufacturers' specified instrument errors, as provided in a survey conducted by the EU-ETS Support Group (ETSG, 2007). The information provided is an indication of potential error ranges and not the expected uncertainty ranges obtained in practice. Appendix B provides additional details about the manufacturers' recommendations for the installation, calibration, and maintenance of these flow meters. The error levels cited refer primarily to random errors that are observed under 'ideal' laboratory conditions and that decrease with repeated measurements. They do not properly account for systematic errors (or bias) where the errors are due to improper installations, inadequate calibrations, or device drift, as discussed above.

However, these manufacturers' specified measurement errors might not be attainable due to the practical operational limitations of the facility. In most petroleum and natural gas industry facilities, detailed inspections, maintenance, and recalibration of process control flow meters are possible only once every few years when process units are shut down for scheduled turnaround.

3.2.2 Fuel gas measurement

API Technical Report 2571 (API, 2011) provides a performance-based methodology for the measurement and reporting of fuel gas consumption. Specifically, considerations are provided for measurement device selection, installation, maintenance, calibration and documentation to achieve the targeted performance in terms of availability and uncertainty. If the performance of any installed measurement device is determined not to be in compliance with an acceptable level of uncertainty, the measurement device, its installation, or maintenance practices, etc., can be upgraded. Techniques are described to assess the uncertainty contribution of individual components of fuel gas measurement systems and the overall facility fuel gas measurement uncertainty.

Following the guidance and calculation procedures of this TR 2571 provides for achieving cost-effective fuel gas measurements of appropriate quality. In most cases, the rigorous requirements of industry standards intended for custody transfer quality measurements can be reduced and still achieve the desired measurement uncertainty.

TR 2571 addresses the most common fuel gas measurement devices in use and contains:

- A brief description of the working principles of different types of fuel gas meters and their influence parameters;
- Installation recommendations;
- A uniform method to ascertain the measurement uncertainty;

Table 3-3. Compilation of specifications for common flow meters[a]

Meter Type	Medium	Technical Description	Manufacturers' Reported Errors[b]
Rotary meter (Expected life span: 25 years)	Gas	The rotary flow meter is a type of positive displacement (PD) flow meter that is widely used for utility measurements of gas flow. Rotary flow meters have one or more rotors that are used to trap the fluid. With each rotation of the rotors, a specific amount of fluid is captured. Flow rate is proportional to the rotational velocity of the rotors. Rotary meters are used for industrial applications.	0-20% of the measurement range: 3% 20-100% of the measurement range: 1.5%
Turbine flow meter (Expected life span: 25 years)	Gas	Turbine flow meters have a rotor that spins in proportion to flow rate. Many of those used for gas flow are called axial meters. Axial turbine meters have a rotor that revolves around the axis of flow. Axial meters differ according to the number of blades and the shape of the rotors. Turbine meters are used as billing meters to measure the amount of gas used at commercial buildings and industrial plants.	0-20% of the measurement range: 3% 20-100% of the measurement range: 1.5%
Bellows meter (Expected life span: 25 years)	Gas	The bellow gas meter performs volumetric measurement via its bellows. The measurements are based on the principle that the flexible bellows are periodically filled and emptied. A major problem with the bellows system is the residue in the pipe. The internal mechanisms fail to perform their tasks due to such residue, causing the meter to dysfunction and fail to perform a sound measurement.	0-20% of the measurement range: 6% 20-100% of the range: 4%
Orifice meter (Expected life span: 30 years)	Gas and Liquid	Orifice meters belong to the category of differential pressure flow meters that consist of a differential pressure transmitter, together with a primary element, such as the orifice plates. The orifice plates place a constriction in the flow stream, and the differential pressure transmitter measures the difference in pressure upstream and downstream of the constriction. The transmitter or a flow computer then computes flow using Bernoulli's theorem. Orifice plates are the most widely used type of primary elements. Their disadvantages are the amount of pressure drop caused, and the fact that they can be knocked out of position by impurities in the flow stream. Orifice plates are also subject to wear over time.	30-100% of the measurement range: 1.5%
Venturi meter (Expected life span: 30 years)	Gas and Liquid	Venturi meters are another example of differential pressure flow meters, as described under orifice meters above. In this case, the primary element is a Venturi flow nozzle. Venturi meters are especially suited to high-speed flows. They are also used for custody transfer of natural gas.	20-100% of the measurement range: 1.5%
Ultrasonic meter (Expected life span: 15 years)	Gas and Liquid	There are two main types of ultrasonic flow meters: transit time and Doppler. The transit time meter has both a sender and a receiver. It sends two ultrasonic signals across a pipe at an angle: one with the flow, and one against the flow. The meter then measures the "transit time" of each signal. The difference between the transit times with and against the flow is proportional to flow rate. Doppler flow meters rely on having the signal deflected by particles in the flow stream and the frequency shift in proportion to the mean fluid velocity.	1-100% of the measurement range: 0.5%

Table 3-3. Compilation of specifications for common flow meters[a] (continued)

Meter Type	Medium	Technical Description	Manufacturers' Reported Errors[b]
Coriolis meter (Expected life span: 10 years)	Gas and Liquid	Coriolis flow meters contain one or more vibrating tubes. These tubes are usually bent, although straight-tube meters are also available. The fluid to be measured passes through the vibrating tubes. It accelerates as it flows toward the maximum vibration point, and slows down as it leaves that point. This causes the tubes to twist. The amount of twisting is directly proportional to mass flow. Position sensors detect tube positions.	1-100% of the maximum measurement range: 1%
Vortex meter (Expected life span: 10 years)	Gas and Liquid	Vortex flow meters are one of the few types of meters, besides differential pressure, that can accurately measure the flow of liquid, steam, and gas. Vortex flow meters operate on the von Karman principle of fluid behavior, where the presence of obstacles in the fluid path generates a series of vortices called the von Karman street. To compute the flow rate, vortex flow meters count the number of vortices generated.	10-100% of the measurement range: 2%
Gas Meter with Electronic Volume Conversion Instrument (EVCI) **(Expected life span: 10 years)**	Gas	An electronic device designed for the primary purpose of converting a volume of gas measured at one set of conditions to a volume of gas expressed at another set of conditions. The device incorporates integral (internal or external) temperature and/or pressure measurement transducers. It may be directly mounted onto a single meter (with mechanical drive or magnetic drive coupling) or connected to a remotely located meter from which it is fed volumetric pulses. The device may perform additional functions such as super compressibility correction, meter accuracy curve correction (linearization), and energy calculations.	For 0.95-11 bar and -10 – 40°C: 0.5%

Notes:

[a] Based on material presented in Appendix I of the ETSG, July 2007 survey summary document and sources cited.

[b] The error levels specified are those reported by the manufacturers when instruments are calibrated under laboratory conditions.

- A recommended method to determine the frequency of maintenance;
- Performance verification or calibration of the meter and secondary instruments; and
- Other relevant and necessary information.

Fuel gas can be measured by different types of flow meters, and the selection of a meter typically depends on several factors such as operating conditions and their variability, desired (or required) accuracy, cost of installation, life expectancy, and other applicable factors.

The uncertainty of measurement depends on the measurement equipment selected for the application; proper installation of the equipment; the ability to inspect, verify, or calibrate the various measurement system components; and the frequency of those maintenance activities. The performance of the meter may also depend on the piping configuration and compensation for variability of operating pressure, temperature, and fluid composition.

An example application of the TR 2571 method is provided in Section 5.3.3.

3.2.3. Integrated measurement systems

As indicated above, the uncertainty of flow measurements depends not only on the hardware selected but also on how hardware performs under field conditions. The integrity and accuracy of the overall measurement system also depends on the calibration methods and calibration equipment used and the calculation protocols embedded in the operating software, along with a combination of factors as indicated below:

- Design, installation, and operation of the flow measuring device;
- Choice of measurement equipment (charts, transmitters, smart transmitter, analog/digital converters, data loggers, etc.;
- The means of data transmission (analog, pneumatic, digital, manual);
- The calculation procedure and means for computation (chart integration, flow computer, laptop, etc.;
- The frequency of calibration checks and meter calibrations;
- The effects on the operation/calibration of ambient temperature, fluid temperature and pressure, response time, atmospheric pressure and the like; and
- Proper unit conversion from ambient conditions to designated standard conditions.

The majority of flowmeters used in the petroleum and natural gas industry typically are either mechanical or pressure-based flows, many of which incorporate electronic devices that can correct for varying pressure and temperature (i.e., density) conditions, and non-linearity, and for the characteristics of the fluids being measured. When electronic transducer-based systems are used for pressure measurements, ASTM developed a standard practice guide for static calibration that is designed to ensure reliable conversion from system output to pressure readings for both laboratory and field use (ASTM D5270-95).

It is important to recognize that site-specific parameters may influence the measurements. Since the principle of operation and differing influence parameters have varying degrees of influence by meter type, it is important to identify and define the significant influence factors for a meter when determining the total or combined measurement uncertainty.

Exhibit 3-3 below provides a checklist of factors to consider when evaluating the uncertainty of flow measurements used for GHG emissions quantification. Additional analyses are required to convert this individual measurement uncertainty to an assessment of the uncertainty range of annual measurements.

EXHIBIT 3-3: FACTORS TO CONSIDER WHEN EVALUATING UNCERTAINTY OF FLOW MEASUREMENTS USED FOR GHG EMISSION CALCULATIONS

a) Confidence range of the measurement instrument

- Manufacturers' anticipated measurement errors for common flow meters could be used (Table 3-3) if on-site calibration data are not available

b) Errors associated with "context-specific" factors

Such factors may include the following considerations:

- Are measurement instruments installed according to the manufacturer's requirements?
- Is the measurement instrument designed for the medium (gas, liquid, solid substance) for which it is being used?
- If manufacturer's data are not available, are the instruments operated according to the general requirements applicable to that measurement principle?
- Are there any other factors that can have adverse consequences on the uncertainty of the measurement instrument? (i.e., how the measurement instrument is used in practice).

c) Pressure and temperature corrections for gas meters

- Pressure and temperature corrections usually are applicable to determine the amount of gas volume though they may be applied to the measurement of liquids materials, such as in fuel pumps.
- The actual amount of gas flow has to be corrected for pressure and temperature to the specified standard conditions to avoid major systematic errors.

d) Determination of total uncertainties

- Individual uncertainties determined in a), b), and c) above

3.3 Sampling and analysis for quantifying GHG emissions

The emission measurement process comprises either direct measurement at the source level, or collection of samples and their subsequent analysis in the laboratory to determine concentrations and ultimately the conversion to mass emissions using the quantified flow measurements discussed above. Sampling and analysis are part of the same measurement process and their combined contribution to emissions estimation uncertainty is obtained by their combined variances, as detailed in Section 5. Emission measurement uncertainties for the processes of sampling and analysis depend on random errors, measurement precision, and systematic errors or bias of the measurement process.

3.3.1 Gaseous samples collection and handling

Proper collection and handling of natural gas samples could have a major impact on the accuracy and representativeness of the analytical measurements based on these samples. Analyses of gas samples are used for multiple purposes and are applied to a variety of calculations including determination of heating values, gas density and viscosity, hydrocarbon dew point, and compressibility. These analyses are essential for obtaining information about the gas composition, including contaminants in the gas stream. Calculations based on these analyses are essential to optimization of process conditions, determination of adherence to contractual specifications, or estimation of GHG emissions when such a stream is combusted.

The API MPMS provides specific details for collecting and handling natural gas samples for critical measurements such as custody transfer (API, 2006). Exhibit 3-4 provides guidance on general considerations of inaccuracies that might be introduced in the measurement system when collecting samples that are used for carbon content and/or heating value determinations for GHG emissions. At the same time, designing a sampling and analysis system always should take into account regulatory requirements and contractual obligations.

EXHIBIT 3-4: KEY FACTORS AFFECTING GAS SAMPLING AND ANALYSIS UNCERTAINTY

a) Inappropriate sampling techniques or equipment

- All sampling methods would require the use of a sample container for transporting the sample from the field location to the laboratory.
- Whenever practical, samples should be collected on a flow proportional or flow weighted basis, since spot samples – by their nature – may not fully represent a gas stream of varying composition.
- Gaseous samples of interest are a mixture of organic and inorganic gases, and their integrity will be compromised.

b) Inappropriate sample conditioning and handling

- Bias could be introduced if any components of a sample are either depleted or augmented during the sampling, transport, or laboratory handling phases prior to analyses.
- Condensation and revaporization of hydrocarbons can cause significant distortions in the gas sample.
- Care should be taken to sample above the hydrocarbon dew point and/or to prevent retrograde condensation when pressure is reduced during sampling.

c) Collection of samples from non-representative locations and/or under non-representative operating conditions

- Sampling systems that are used in conjunction with on-line analyzers, such as chromatographs or gravitometers, typically are designed to extract, condition, and deliver a representative sample to the analyzer.
- Sampling lines are kept as short as possible in conjunction with proper heating and insulation to avoid condensation.
- The flow rate of the sampling system is adjusted to allow for close to real time data, while at the same time not increasing the flow to a level that might lead to turbulence.

d) Inappropriate analytical methods

- The threshold sensitivity of the analytical methods used are typically those that are well

3.3.2 Quantifying sampling precision

Quantifying sampling precision requires that primary samples be collected according to a defined protocol, but randomized in some way for each sample (in either space or time). For example, a pre-selected percentage of the total number of samples can be collected in duplicate and the repeatability of the measurement determined from these duplicate samples. Additionally, duplicate gaseous samples can also be analyzed in duplicate and thus a full record of both sampling and analysis system variations can be obtained. In this case, the sampling component of the variance represents the natural variability of the sampling target as well as any errors in the sample collection and preparation.

When in situ measurement techniques are used (e.g., infrared gas analyzer), both the sampling and analysis are addressed at the same time. The determination of sampling bias, or the difference between the mean of several measurements and the true value, is more difficult. Biases could arise from several causes such as sample fouling, inappropriate handling, or unrepresentative sampling. The "true" value for the concentration of unknown species in a sample is never known since it is impossible to construct a true reference laboratory standard for an unknown mixture of gases.

Sampling uncertainty is a relatively new concept whose importance is slowly beginning to be recognized. Recent research has shown that sampling uncertainty is often far greater than analytical uncertainty. Therefore, combining sampling and analytical uncertainties to provide an estimate of measurement uncertainty is an important component of quantifying the overall uncertainty of GHG estimations that rely on sampling gaseous fuels of varying composition.

3.4 Carbon content measurement practices

Different types of gas chromatography (GC) systems are normally used to analyze the carbon content of gaseous streams. The GC systems might be laboratory based or set up as an online device for automated collection of samples and their analysis. The systems typically are set up to analyze the individual components in the sampled gas and provide detailed reports of properties including composition, calorific value, and density.

The results of the determination of individual or groups of carbon-containing species are then used to assess the total emissions of CO_2 upon combustion of such a fuel. Several key considerations include:

- If the method is capable of determining CO_2 content with the rest of the carbon containing species, no further correction of the carbon content data is required to properly account for all CO_2 emissions.
- If the method is set up to provide information only on hydrocarbon species, the CO_2 content should be obtained by an independent measurement and added to the fuel carbon content data.
- If the method is capable of a quantitative determination of CH_4 content, these data can be used separately for calculating evaporative and processing leaks along with venting losses.
- All carbon content measurement data should be used in conjunction with the applicable fuel flow measurements when calculating emissions.

3.4.1 Laboratory-based measurements

Several ASTM and ISO methods are available for determining the composition and carbon content in the natural gas range as well as for liquid and solid fuels. The methods usually document measurement precision in terms of repeatability and reproducibility of the measurement when comparing multiple sets of measurements. Although the terms "repeatability" and "reproducibility" are applicable to all measurement situations (see Appendix A for terminology and definitions), they are used here in the context in which they are defined in ASTM standards:

- *Repeatability* is defined as the difference between two successive results obtained by the same operator with the same apparatus under constant operating conditions on identical test materials
- *Reproducibility* is the difference between two results obtained by different operators in different laboratories on identical test materials.

When using a natural gas measurement method for refinery fuel gas, care should be taken to ensure that the range of compositions of individual components is within the bounds specified by the method. Table 3-4 lists selected commonly used laboratory measurement methods that are frequently used for the determination of fuel carbon content. Additional details about these methods and further discussions of their main features are provided in Appendix D.

3.4.2 On-line measurements

On-line determination of fluid stream compositions is quite challenging due to possible variations in these compositions. This is especially notable for self-generated fuel gas such as refinery fuel gas or other processing plant gas. Conversely, for commercial products such as natural gas, liquid fuels, coal and coke, or for the analysis of associated gas in exploration and production operations, the challenges are more related to the ability to analyze multiple streams rapidly and ascertain that they all are within a desired property range.

Instrumentation in this field has been developed to provide a measurement of stream components in order to achieve optimum control and assure product quality. The configurations of such analyzers are customized to accommodate typical site parameters and operating practices. Most such analyzers are designed with ASTM and ISO standards in mind, and their calibration routines are designed to provide both reported data and its associated uncertainty. As mentioned previously, the two primary applications are for refinery gas analyzers and natural gas analyzers, and these are discussed briefly below.

- *Refinery Gas Analyzer*: Refinery gas samples are delivered to the sample inlet of the GC after passing through a sample conditioning system that selectively removes any liquid fractions and particulate matter from the sample. This ensures that only the gas phase sample is delivered to the analyzer. An internal vacuum pump draws this conditioned

Table 3-4. Summary of selected carbon content measurement methods

Method	Title	Brief Description	Measurement Precision[a]
ASTM 1945-03	*Analysis of Natural Gas by Gas Chromatography*	- Covers the determination of the chemical composition of natural gases and similar gaseous mixtures within specified ranges of applicable composition for individual components	- Repeatability ranges from 0.01- 0.10 mole% - Reproducibility ranges from 0.02-0.12 mole%Version 2,
ASTM 1946-90 (Reapproved 2006)	*Analysis of Reformed Gas by Gas Chromatography*	- Used for determination of chemical composition of reformed gases and similar gaseous mixtures - Applicable to mixtures containing: hydrogen, oxygen, nitrogen, carbon monoxide, carbon dioxide, methane, ethane, and ethylene	- Repeatability ranges from 0.05 - 0.5 mole% - Reproducibility ranges from 0.1 - 1.0 mole%
ASTM UOP539-97	*Refinery Gas Analysis by Gas Chromatography*	- Used for determining the composition of refinery gas samples or expanded liquefied petroleum gas (LPG) samples obtained from refining processes or natural sources	- Quantification from 0.1-99.9 mole% for a single component or composite - For hydrogen sulfide, quantitative results between 0.1-25 mole%
ISO 6974 (Six parts)	*Natural Gas - Determination of Composition with Defined Uncertainty by Gas Chromatography*	- Describes a gas chromatographic method for the quantitative determination of the content of hydrogen, helium, oxygen, nitrogen, carbon dioxide and C1 to C8 hydrocarbons in natural gas samples - Uses either two or three packed or capillary columns combinations	- Relative repeatability: - 2% for species < 1.0mole%; - 0.8% for species 1-50mole% - Relative reproducibility: - 4% for species < 1.0mole% - 1.6% for species 1-50mole%
ASTM D2650-04	*Standard Test Method for Chemical Composition of Gases by Mass Spectrometry*	- Applicable for the quantitative analysis of gases containing specific combinations of the following components: hydrogen; hydrocarbons (up to 6-carbons per molecule); carbon monoxide; carbon dioxide; mercaptans (1-2 carbons per molecule); hydrogen sulfide; and air (N_2, O_2, and Ar)	- NOT applicable for constituents < 0.1 mole%. - Developed on a specific type of measurement system - Users have to modify for their instrument.
ASTM D5291 - 10	*Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants*	- Applicable to samples such as crude oils, fuel oils, additives, and residues for carbon and hydrogen and nitrogen analysis - Tested in the concentration range of at least 75 - 87 wt% carbon, at least 9 - 16 wt% hydrogen, and 0.1 - 2 wt% nitrogen	- NOT recommended for the analysis of volatile materials such as gasoline, gasoline-oxygenate blends, or gasoline type aviation turbine fuels

[a] Measurement precision data is provided as an indication of attainable precision if all steps of the methodology are adhered to as described in the methods procedures.

sample into each injector, which then injects the mixture onto each of the columns for analysis. A complete analysis of hydrogen, saturated and olefinic hydrocarbons (C1-C5, and C6+ grouped peaks), plus fixed gases (O_2, N_2, CO, and CO_2) typically is performed. Precise "retention times" information and component areas translate into accurate component identification and quantification of the relative magnitude of individual components present in refinery gas.

- *Natural Gas Analyzer:* These types of analyzers are applicable to natural gas samples from wellhead to pipeline-quality gas. Samples are introduced using sample cylinders, Tedlar bags, or by direct connection to the pipeline or wellhead sampling points. Usually, two chromatographic modules are used to quickly separate and measure the individual components in natural gas. The analyzer separates and measures the permanent gases and hydrocarbons present via an optimized, dual-channel portable gas chromatograph. Wellhead samples may often contain significant amounts of H2S. Many instruments take this into account and there are no interferences, which mean that H2S can be measured from 50 parts per million (ppm) to 30-mole%.

3.4.3 Carbon content calculation

API Technical Report (API, 2013) provides guidance and a methodology for determining the carbon content of hydrocarbon-based petroleum and petrochemical products, and the uncertainty of the average carbon content as calculated from multiple samples taken during a sampling period. This method is intended to make use of industry-accepted mixture property data and test methods with no new or modified test methods introduced in this document. The method is applicable to carbon-content-based reporting or trading for all gaseous and liquid hydrocarbons.

It is a companion to API TR 2571 on Fuel Gas Measurement (see Section 3.2.2), which provides guidance on measuring the volume/mass of process fuel gas or feedstock.

Equations for the calculation of carbon content for a pure component and a product analysis typically are based on the definitions found in Section 4.3 of the API *Compendium* (API, 3rd edition, August 2009). The carbon content of a mixture is the weighted average of the individual component carbon contents and can be calculated from the compositional analysis of the mixture (see API *Compendium* Table 3-6). Hydrocarbon gas chromatographic analysis is generally reported in mole fraction or mole percent, and hydrocarbon liquid chromatographic analysis is generally reported in mass fraction or mass percent; therefore, calculations for both types are included in API's TR 2572. Molecular weights of hydrocarbon components can be found in the T*able of Physical Properties for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry* (GPA, 2145).

Carbon content can also be estimated from other process or fuel supply properties such as heating values that are correlated to the fuel type and carbon content. The API *Compendium* (3rd edition, August 2009) summarizes a number of these correlations in its Tables 3-8 and 3-9, which provide carbon content and heating value information for petroleum products and natural gas heating value ranges, respectively. Use of these correlation factors works well for compositions with limited variability or for fuel supplies where the heating value is continuously monitored or controlled.

For process or fuel supplies with widely varying compositions or that are subject to periodic upset conditions, the frequency, duration and carbon content of this variability needs to be characterized to accurately calculate the average carbon content. Section 3.6 below provides further details on heat content determination.

API TR 2572 provides references and supplemental information on applicable industry practices based on published resources, existing industry standards, industry-accepted physical constants or properties of hydrocarbons for measurement, sampling, sampling frequency, and analysis of hydrocarbon samples. It provides guidance on estimating carbon content sampling period uncertainty based on multiple periodic samples taken at intervals that are independent of the process or fuel supply operation.

To determine the number of samples required to meet a certain average carbon content uncertainty, one can use Equation 3-1 below:

$$\textbf{Number of Sampleas} = \left[\frac{k_{95} \times \dfrac{\sigma}{CC_{average}} \times 100}{TargetPercentCC_{uncertainty}} \right]^2$$

(Equation 3-1)

Where:

Number of samples = the number of samples to be collected

k95 = the 95 % confidence coverage factor (typically assumed to be 3)

σ = the carbon content standard deviation of the samples analyzed

CC = carbon content

Target Percent $CC_{Uncertaint}$ = the target percent uncertainty for the reporting period

This equation could be reversed to derive the level of uncertainty given a specific sampling frequency.

According to the discussion in Annex B of API TR 2572, the uncertainty of reporting period fuel carbon content (i.e., its 95 % confidence interval) is dependent on the number of multiple fuel samples used. Increasing the number of samples reduces the uncertainty of the reporting period average carbon content by the square root of the number of samples.

For example, if the average annual carbon content is determined from monthly fuel sampling and analysis (12 spot samples) and the standard deviation of these 12 samples is 3.9%, the 95% confidence interval for annually reported carbon content will be: $\pm (3\times3.9\% / \sqrt{12})$, or ± 3.4 %. However, if quarterly samples are used (four samples per year with the same sampling standard deviation of 3.9%), the 95% confidence interval for the annually reported carbon content would be + 5.9%.

3.5 Heat content determination

The heating value or calorific value of a substance is the amount of heat released during the combustion of a specified amount of the substance. The calorific value is a characteristic for each substance and is measured in units of energy per unit of the substance, such as: kcal/kg, kJ/kg, J/mole, Btu/m^3. The heat of combustion for fuels is expressed as:

- **HHV:** higher heating value (or gross calorific value or gross energy or upper heating value) is determined by bringing all the products of combustion back to the original pre-combustion temperature, and in particular condensing any water vapor produced.
- **LHV:** lower heating value (or net calorific value) is determined by subtracting the heat of vaporization of the water vapor from the higher heating value and treating any water formed as a vapor. The energy required to vaporize the water therefore is not realized as heat.

In the petroleum and natural gas industry, the two most prevalent modes of determining heating values of gaseous fuels are either by measuring it directly, which can be accomplished either by stoichiometric combustion or by calorimetric techniques, or using computational methods that are based on standardized calculation procedures using gas sample composition data. A brief summary of these two types of practices is provided below.

3.5.1 Direct measurements

The heating value indicates the amount of energy that can be obtained as heat by burning a unit of gas. The heating values of a gas depend not only upon the temperature and pressure, but also upon the degree of saturation with water vapor.

As mentioned above, general practices for determining fuel gas heating values rely on either calorimetric techniques or stoichiometric combustion practices. Table 3-5 provides a listing and a brief description of some selected methods for heating value determination for gaseous, liquid, and solid fossil fuels. Further discussion of the main features of these methods can be found in Appendix C.

3.5.2 Computational methods

Heating value may be determined from gas compositional analysis in accordance with a standard practice established by the ASTM for calculating heating values for natural gas and similar mixtures from compositional analysis. ASTM D3588-98 (Reapproved 2003), is the standard recommended practice for calculating heating values, compressibility factors, and relative densities of gaseous fuels (ASTM D3588-98). This practice covers procedures for calculating these quantities at base conditions (14.696 psia and 60°F or15.6°C) for natural gas mixtures from compositional analysis. It applies to all common types of utility gaseous fuels, i.e., dry natural gas, reformed gas, oil gas (both high and low Btu), propane-air, coke oven gas, and other gaseous fractions for which suitable methods of analysis are designated.

The ideal gas heating value and ideal gas relative density are calculated from the molar composition and the respective ideal gas values for the components; these values are then adjusted by means of a calculated compressibility factor.

The ASTM approach recognizes that the calorific value of a mixture, such as in refinery fuel gas systems, is a function of the mol% composition of the individual components of that mixture. For refinery fuel gas, this mixture could contain both carbon containing species, which upon combustion will contribute directly to CO_2 emissions, as well as non-carbon containing species. Hydrogen, for example, is an important contributor to refinery fuel gas heating values but it does not contribute to CO_2 emissions when combusted.

To implement this practice, the user would first determine the molar composition of the gas in accordance with any applicable ASTM or GPA method. For a precise calculation, at least 98% of the sample constituents should be determined as individual components, with no more than a total of 2% in terms of groups of components (e.g. butanes, pentanes, hexanes, and so forth).

An ideal combustion reaction for fossil fuels (that may contain hydrogen) in the ideal gas state can be generally represented as in the reaction depicted in Eq. 3-2:

$$\mathrm{C_aH_b} + \mathrm{cH_2} + \left(\mathrm{a} + \frac{\mathrm{b}}{4} + \frac{\mathrm{c}}{2}\right)\mathrm{O_2} = \mathrm{aCO_2} + \left(\frac{\mathrm{b}}{2} + \mathrm{c}\right)\mathrm{H_2O}$$

(Equation 3-2)

The ideal net heating value is the heating value that is observed when all the water remains in the ideal gas state, while the ideal gross heating value is observed when all the water formed by the reaction condenses to liquid. The difference between them is the enthalpy of vaporization of the water formed during the combustion process. Therefore, the ideal gross heating value for a mixture can be expressed as shown in Eq. 3-3:

$$Hm = \frac{\sum_{j=1}^{n} x_j \times M_j \times H_{mj}}{\sum_{j-1}^{n} x_j \times M_j}$$

(Equation 3-3)

Where:

x_j = the mole fraction of Component j;

M_j = the molar mass of Component j;

n = the total number of components; and

H_{mj} = the ideal gross heating value per unit mass for Component j (at 60°F or 15.6°C), as tabulated in ASTM D3588 (ASTM, 2003). Values of H_m are independent of pressure, but they vary with temperature.

Errors to be considered when computing heating values include: errors in the heating values of the mixture components and errors in determining the mixture composition. The uncertainty ranges of the heating values for the components cited in the ASTM practice are about 0.03%. These errors may affect the agreement between calculated and measured heating values; however, these errors are negligible when compared to the errors associated with the determination of the composition of individual species. Appendix D contains a listing of common energy and fossil fuel unit conversion factors that could be used for these and other calculations discussed in these document.

Table 3-5. Summary of selected heating value measurement methods

Method	Title	Brief Description	Measurement Precision (*)
ASTM D4891-89 (Reapproved 2006)	*Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion*	– Used for the determination of heating value of natural gases and similar gaseous mixtures within a specified composition range – Provides an accurate and reliable procedure for regulatory compliance, custody transfer, and process control	– Repeatability: 0.76 Btu/scf, 95% confidence: 2.1 Btu/scf. – Reproducibility: 1.67 Btu/scf, 95% confidence: 5.1 Btu/scf. – Average bias: within 0.1% from reference value
ASTM D1826-94 (Reapproved 2003)	*Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter*	– Used for the determination of the total calorific (heating) value of fuel gas produced or sold in the natural gas range from 900-1200 Btu/scf – Provides a reliable method for measurement on a continuous basis with a recording calorimeter	– Weekly standardization with methane – Errors < 0.5% within a week after standardization – Higher errors expected for longer standardization periods
ASTM D7314-08	*Standard Practice for Determination of the Heating Value of Gaseous Fuels using Calorimetry and On-line/At-line Sampling*	– Used to determine the heating value of gaseous fuels with at-line and in-line instruments – Suitable for periodic operation on a continuous basis – Suitable for monitoring systems for tracking properties when using or producing gaseous fuels in industrial processes	– No generic precision data apply here since this is a practice and not a method – The installation and operation of particular systems vary with process type, performance, and regulatory requirements
ASTM D4809-13	*Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)*	– Covers determination of the heat of combustion of hydrocarbon fuels – Can be used for a wide range of volatile and nonvolatile materials where slightly greater differences in precision can be tolerated – Under normal conditions, the method is directly applicable to such fuels as gasoline, kerosenes, Nos. 1 and 2 fuel oil, Nos. 1-D and 2-D diesel fuel and Nos. 0-GT, 1-GT, and 2-GT gas turbine fuels	– Strict adherence to all details of the procedure is essential – The error contributed by each individual measurement that affects the precision shall be < 0.04 %, insofar as possible
ASTM D5865-13	*Standard Test Method for Gross Calorific Value of Coal and Coke*	– Pertains to the determination of the gross calorific value of coal and coke by either an isoperibol or adiabatic bomb calorimeter	–

(*) Measurement precision data are provided as an indication of attainable precision if all steps of the methodology are adhered to as described in the methods procedures.

3.6 Venting and fugitive emissions measurements

Vented emissions are releases to the atmosphere that are due to process or equipment design, or operational practices. Vented emissions may come from a variety of emission points or non-fired stacks, or sometimes from flares as is commonly the approach used for categorizing emissions in GHG emission inventory compilations that adhere to the IPCC 2006 national inventory guidance. In all cases, these are part of the process design and are intended for pressure relief purposes. Fugitive emissions are due to equipment leaks from piping components and a variety of seals found in typical petroleum and natural gas installations.

Vents may either be intermittent or continuous. Intermittent applications may include the disposal of waste volumes from emergency pressure relief episodes, operator initiated or instrumented depressurization events, plant or system upsets, well servicing and testing, pigging events, and routine blowdown of instruments, drip pots, and scrubbers. Continuous applications may include disposal of associated gas, treater off-gas and tank vapors at oil production facilities, casing gas at heavy oil wells, process waste, or byproduct streams. Depending on local requirements, some of the vented streams may be either captured for on-site use/sale or flared, depending on the economic value of the stream and the availability of local infrastructure.

These emission sources tend to be very specific to the type of operation and detailed methods for quantifying these emissions are provided in Section 5.0 and 6.0 of the API Compendium (3rd edition, August 2009).

Table 3-6 provides a summary of the vented and fugitive emission source types and their measurement requirements under the EPA's GHG Reporting Program (GHGRP). The emissions sources are categorized around the subparts of the EPA regulation: Petroleum and Natural Gas Systems (Subpart W) and Petroleum Refining (Subpart Y).

Table 3-6. GHGRP measurement methods for vented and fugitive emission sources

Emission Category	Source Type	GHGRP Measurement Method
	Petroleum and Natural Gas Systems	
Vented Emissions	– Pneumatic device and pump vents, – Gas well liquids unloading – Gas well completions – Gas well workovers – Storage tanks – Dehydrators – Acid gas removal	**Engineering Estimate** using monitored process operating parameters and either simulation models or emission factors
	– Compressor wet seal vents – Compressor rod packing vents – Transmission condensate tanks	**Direct Measurement** where meters depending on source measured
Fugitive Emissions	– Compressor station leaks – Processing plant equipment leaks – Fugitives and non-compressor plant/station fugitives	**Leak Detection Surveys** in conjunction with emission factors for identified "leaking" components
	– Valves, connectors and pump seals from: • Offshore petroleum and natural gas production • Onshore petroleum and natural gas production • Local distribution company mains, • Service lines, vaults, and other inaccessible sources	**Equipment Count** in conjunction with applicable population emission factors
Vented Emissions	– Fluid Catalytic Cracking – Catalyst regeneration – Hydrogen production – Acid gas removal – Sulphur recovery – Cokers	**Engineering Estimate** using monitored process operating parameters and either simulation models or emission factors

3.6.1 Vented emission measurements

The term "GHG emission measurement" may refer to direct measurement of emissions, the use of engineering equations or models that rely on some measured operating parameters, or known activities with default emission factors. The accuracy of these estimation methods varies and should weigh the considerations outlined in Section 2.5.

The sections below focus on three types of technologies that can be used as appropriate to measure or quantify the magnitude of vented emissions.

- ***High Volume Sampler****:* a high volume sampler consists of a simple fixed-rate induced flow sampling system to capture and measure the volume of emissions. The emissions and the air surrounding the emissions source are drawn into the instrument using a sampling hose. The instrument measures the flow rate of the captured volume of air and emissions mixture, and the concentration of hydrocarbons in the mixture. A separate sample of the ambient air is taken by the instrument to correct for the background concentration of hydrocarbons in the ambient air. High volume samplers are limited in the range of flows and emission rates that they can capture; therefore, large component emissions and many vent emissions are above the high-volume sampler capacity and therefore require the use of other measurement instruments.
- ***Meters:*** several types of meters measure liquids and gas flow rates, and can be used for measurement of emissions from sources where the volume of emissions is high, as in vent stacks. Typical meters include: rotameters, turbine meters, hot-wire anemometers, pitot tube flow meters, and vane anemometers. Further details on flow measurement practices are provided in Section 3.1 and the uncertainty associated with flow measurements for GHG inventories is addressed in Section 3.2.

  To ensure accurate measurements when using metering, all emissions from a single source are channeled directly through the meter. An appropriately sized meter should be used to prevent the flow from exceeding the full range of the meter, while having sufficient momentum for the meter to register continuously in the course of measurement.
- ***Calibrated Bagging****:* a calibrated bag is used to enclose an emissions source to completely capture all the leaking gas. The volume of the bag and time required to fill it is used to determine the mass emission rates. This is a suitable technique for emission sources that are within a safe temperature range and can be safely accessed. The speed of measurement is highly dependent on the emissions rate and the results are susceptible to human errors that are introduced when enclosing the emission source and taking the measurement data.

  Calibrated bags can be used only where the emissions are at near-atmospheric pressures and the entire emissions volume can be captured for measurement. Using these bags on high pressure vent stacks can be dangerous. The mass emission rate is usually estimated as the average of three measurements of the time required to fill the bag followed by chemical analysis of the bag content to determine mass emission rates of individual species. Section 3.5 presents further information that is specific to carbon content measurements.

3.6.2 Fugitive emission measurements

Similar to vented emissions (Section 3.6.1), fugitive GHG emissions from equipment leaks may be quantified either by direct measurement of leaking components or by a count of the myriad of components and associated default emission factors. The accuracy of the emission estimate increases with more precise knowledge of the number of components of each type and service, and with characterization of their leaking status. Although the use of default emission factors is expedient in some instances - especially for remote locations - it may lead to overestimating the contribution of emissions from leaking process components due to the conservative nature of the emission factors commonly used.

When site-specific measurements are undertaken, leak detection has been traditionally performed by Toxic Vapor Analyzer (TVA) and the Organic Vapor Analyzer (OVA). New gas imaging technologies are now available using remote infrared detection of the leaking gases. One of these methods could be used in the field depending on factors such as size and complexity of facilities and local requirements.

- ***Organic Vapor Analyzers***: OVA instruments are equipped with flame ionization detectors that are used to detect the presence of hydrocarbons and measure their concentrations at the leak interface. It consists of a probe that is moved close to and around the potential emissions locations where emissions are detected when the instrument records positive readings on its monitoring scale. However, these concentrations are not a true measure of mass emission rate, but represent "screening" values. The component screened is said to be leaking if the measured concentration exceeds a defined concentration threshold that is defining a "leak."

  This method is suitable for use for all equipment leak detection that is safely accessible at close range. For each potential emissions source, all joints, connections, and other potential paths to the atmosphere should be monitored for emissions. Further guidance on operation and calibration of these instruments is provided by EPA (EPA, method 21 guidelines).

- ***Remote Infrared Gas Imaging Detectors:*** these instruments are based on the ability of hydrocarbon compounds to absorb infrared radiation. The instruments use this property to scan a given facility area and provide distinct imaging of the gas that is leaking from piping components.

  To be able to detect the visually displayed image of the leaking components, it is essential to have an appropriate background. Therefore to identify all emission sources, the operator inspects the emissions source from multiple angles or locations until the entire source has been viewed without visual obstructions.

  The minimum detectable quantity of equipment leaks using an IR instrument depends on a number of factors including manufacturer, viewing distance, wind speed, gas composition, ambient temperature, gas temperature, and type of background behind the leaking components. For best survey results, equipment leak detection should be performed under favorable conditions, such as during daylight hours, and in the absence of precipitation and high wind. EPA's Alternative Work Practice (AWP) provides further instructions for calibration and operation including the ability to detect a minimum flow rate (see EPA, 2008: 40 CFR, Part 65, Section 7) before each use.

3.7 Laboratory management system

An additional consideration for uncertainty of GHG measurements is the credibility and technical veracity of the laboratory performing the requested tests, as specified by different programs. For example, in the EU-ETS program the Monitoring and Reporting Guidelines (MRG) require the demonstration of laboratories management systems (EU-ETS MRGs, 2007; Section 13.5). Any laboratory used to determine an emission factor, calorific value, carbon content, or composition data should be accredited according to ISO 17025:2005. If non-accredited laboratories are used, the EU regulations provide specific requirements for the validation and testing of such laboratories.

ISO/IEC 17025:2005 (ISO/IEC 17025, 2005) is not intended to be used for overall laboratory certification, and it does not address compliance with regulatory and safety requirements. It merely emphasizes the need for a well-developed and communicated laboratory management system that addresses areas such as: quality, administrative procedures, and technical systems that govern the operations of the laboratory. The ISO standard highlights the need for laboratories to ensure that their personnel are aware of the relevance and importance of their activities to the achievement of the management system's objectives.

The standard specifies the general requirements for demonstrating competence to carry out specific tests and calibrations, including field sampling. It covers testing and calibration procedures that are performed using standard methods, non-standard methods, and laboratory-developed methods. This standard may be applied to all organizations performing tests and/or calibrations, including both internal companies' laboratories as well as external contract laboratories.

ISO/IEC 17025:2005 is applicable to all laboratories regardless of the number of personnel or the extent of the scope of testing and/or calibration activities. When a laboratory does not undertake one or more of the activities covered by ISO/IEC 17025:2005, such as sampling and the design/development of new methods, the requirements of those clauses would not apply.

As part of compliance with ISO/IEC 17025:2005, laboratories that want to be accredited to this standard are mandated to seek feedback, both positive and negative, be it from in-house users or from external customers. The information gathered is expected to help laboratories improve their management systems, their testing and calibration activities, and customer service. The ISO standard seeks to improve laboratory measurement proficiency and accuracy by continual improvement of the effectiveness of laboratory management systems and the implementation of quality policy, quality objectives, internal audits, data analysis, corrective and preventive actions and periodic management review.

4. OVERVIEW OF REPORTING PROGRAMS' UNCERTAINTY REQUIREMENTS AND TOOLS

The development of GHG emissions inventories and their reporting have evolved over the past two decades starting with IPCC rules designed originally for national reporting under the UNFCCC (IPCC, 1996 and 2006 guidelines). Emerging from those rules were guidelines and international standards more applicable to corporate reporting such as the GHG Protocol Corporate Standard (WRI/WBCSD, 2004) and the International Standards Organization (ISO) and its family of 14064 standards (ISO, 2006). Since the development of the World Resources Institute (WRI) GHG Protocol Corporate Standard, WRI and the World Business Council for Sustainable Development (WBCSD) have collaborated in an initiative to assist developing countries and rapidly industrializing countries (such as Brazil, China, India, Mexico and the Philippines) to use the GHG Protocol as a foundation for their GHG programs[2].

The sections below provide an overview of select GHG reporting programs that are pertinent to global petroleum and natural gas operations. An emphasis is placed on summarizing various program approaches for addressing uncertainty and the availability of calculation tools.

SECTION FOCUS

This section provides an overview of the uncertainty requirements from various GHG reporting programs applicable to the petroleum and natural gas sector, and compares elements of programs and their uncertainty targets. Where available, calculation tools available to assist reporters in quantifying the uncertainty of GHG emission estimates for these programs are also introduced.

The subsections address:

- Global uncertainty approaches applicable to the petroleum and natural gas sector;
- Uncertainty targets for mandatory programs; and
- Tools for calculation uncertainty.

4.1 Global approaches applicable to petroleum and natural gas sector

Global trends indicate that a growing number of companies assess and address the potential threats and opportunities of climate change for their business. At the same time, there is also an increasing demand from governments and other stakeholders for corporate climate change-related information, therefore, encouraging or mandating companies to disclose GHG emissions data. This has given rise to a myriad of sector-specific guidance for voluntary reporting of GHG emissions, such as for the petroleum and natural gas industry (IPIECA, 2011), along with increased requests from investors for data disclosure (CDP, 2010). At the same time, a wide range of regulatory schemes are being developed that mandate GHG emissions reporting by installations and business entities at the national and regional levels (OECD, 2012).

For example, the EU ETS now operates in 30 countries and covers CO_2 emissions from some 11,000 installations. In Japan, in 2009, over 11,000 enterprises reported their CO_2 emissions under the mandatory GHG Accounting and Reporting system, accounting for about half of the total emissions of Japan nationwide. In the U.S. around 8,000 entities reported data in 2012 under the GHG Reporting Program, covering an estimated 85-90% of total U.S. GHG emissions.

Table 4-1 provides an inter-country comparison of mandatory reporting programs in selected countries with significant petroleum and natural gas industry operations. As indicated in the table, these programs have varying policies for implementing their quality assurance, verification, and uncertainty assessment requirements but they all share the common goal of ensuring the reporting of high quality data to be used as the basis of policy decisions.

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[2] http://www.ghgprotocol.org/programs-and-registries

Table 4-1. Inter-Country comparison of select mandatory GHG reporting programs

Program Elements	Countries					
	Australia	**Canada**	**EU**	**France**	**UK**	**USA**
Program Name	National Greenhouse and Energy Reporting (NGER)	Environment Canada GHG Emissions Reporting Program (GHGRP)	European Union Emissions Trading System (EU-ETS)	Bilan démissions de GES	Greenhouse Gas Emissions Reporting	Greenhouse Gas Reporting Program (GHGRP)
Inception Date	2009	2004	2005	2011	2009 (Mandatory April 2013)	2009
Legal Authority	National Greenhouse and Energy Reporting (NGER) Act of 2007	Canadian Environmental Protection Act (CEPA, 1999) – Section 46	EU Regulation 601/2012 (21-JUN-2012), Monitoring and Reporting of GHG emissions pursuant to Directives 2009/29/EC and 2003/87/EC	"Grenelle II" n°2010-788, 12 July 2010 (Article 75)	Climate Change Act of 2008 and pending regulations	FY2008 Consolidated Appropriations Act (H.R. 2764; PL 110– 161),
Geographical Coverage	Australia	Canada	EU- 28?, Norway, Lichtenstein and Switzerland	France	Global emissions of UK companies	U.S. entities
Gases Reported	6 Kyoto GHGs	6 Kyoto GHGs	Primarily CO$_2$, with provision to include CH$_4$ and N$_2$O in the future	6 Kyoto GHGs	6 Kyoto GHGs	6 Kyoto GHGs + NF3
Reporting Boundaries	Corporate Control	Facility level	Installation	- Companies over 500 employees; - Sub-national government over 50,000 inhabitants; - Public bodies over 250 employees	All London Stock Exchange- listed firms Consistent with GHG Protocol	Facilities Fossil fuels or industrial GHGs suppliers Vehicles and engines manufacturers
Reporting threshold	25 KtCOe (facility) 50 KtCOe (company) Production / consumption > 200TJ	50 KtCO$_2$e (facility)	25 KtCO2e per year (excluding emissions from biomass); Combustion of fuels in installations with a total rated thermal input exceeding 20 MW	No	No	25 KtCOe per year

Table 4-1. Inter-Country comparison of select mandatory GHG reporting programs (continued)

Program Elements	Countries					
	Australia	**Canada**	**EU**	**France**	**UK**	**USA**
	consumption > 200TJ		Combustion of fuels in installations with a total rated thermal input exceeding 20 MW			
Scope of emissions	- Direct operational emissions - Indirect emissions from energy consumption - Other indirect emissions (optional)	- Direct operational emissions	- Direct regular operational emissions - Abnormal events including start-up and shut-down - Emergency situations - Exception of emissions from mobile machinery for transportation purposes.	- Direct operational emissions - Indirect emissions from energy consumption	Direct operational emissions Indirect emissions from energy	Direct operational emissions Potential emissions from distribution of fossil fuels and industrial gases
Calculation methods	- 2009 Technical Guidelines - Australian EFs provided	- Gov't of Canada Technical Guide Based on IPCC Guidelines and Good Practice Guidance - Sector-specific manuals - National EFs and GWPS - Conversion factors and Electricity intensity	- Commission Regulation (EU) No. 601/2012: - Subsection 2 – Activity Data - Subsection 3 – Calculation Factors - Subsection 4 – Specific calculation factors	- Bilan methods démissions de GES - Inspired by ISO 14064-1, 2006 - Consistent with GHG protocol - EFs from ADEME database	DEFRA Guidance on how to measure and report GHG emissions (September 2009)	- Detailed calculation methods for each of the 41 subparts addressing sectors of the economy that are required to report Industry consensus standards for measurements
Reporting	- Annual report to Ministry of Climate Change and Energy Efficiency - Online System Comprehensive Activity Reporting (OSCAR)	- Annual report to Environment Canada - Electronic Data Reporting (EDR) system on the GHG reporting website	- Annual verified report - Information reported in rounded-off tonnes of CO2e	- Every three years	Annual report with financial report	Annual reporting through the EPA's electronic GHG reporting tool (eGGRT)
Quality Assurance	- Internal	- Information should be "verifiable"	- Member States are required to ensure that emissions are monitored in accordance with the monitoring and reporting guidelines.	- Internal	Not specified	- QA/QC checks specified in each of the rule subparts - Guidance for substitution of missing data

Table 4-1. Inter-Country comparison of select mandatory GHG reporting programs (continued)

Program Elements	Countries					
	Australia	Canada	EU	France	UK	USA
Verification	- 3rd party verification not required	- No specific requirements for a 3rd party verification.	- Member States are required to ensure that the reports submitted by operators are verified	- Not required by law	- No specific requirement for 3rd party verification of GHG data	- Self-certification by facilities' registered designated representatives - Verification checks by EPA
Uncertainty assessment	- Required - Uncertainty ranges provided with EFs	- No specified assessment required	- Maximum Permissible Uncertainty for each tier of activity data (Anx II, Table1)	- Not specified beyond GHG protocol guidance	- Not addressed	- Specifications for calibrations in General Provisions (Subpart A)
Citations	http://www.cleanenergyregulator.gov.au/National-Greenhouseand-Energy-Reporting/Pages/default.aspx	www.ec.gc.ca/ges-ghg	http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2012:181:0030:0104:EN:PDF	www.developpement-durable.gouv.fr/IMG/pdf/09003PLAN-CLIMAT.pdf)	www.defra.gov.uk/environment/economy/business-efficiency/reporting	www.epa.gov/climatechange/emissions/ghg-data/index.html

Since not all governments have reporting programs, a few non-governmental initiatives, require or encourage enterprises to quantify and report their GHG emissions. These voluntary initiatives are part of environmental and other non-financial disclosure requirements, with the most notable one being that of the Carbon Disclosure Project, which is backed globally by major investors. Table 4-2 provides a high level comparison of the scope and coverage of mandatory reporting in the USA. under the GHGRP as compared to the voluntary disclosure of GHG emissions under the CDP, which brings into the voluntary CDP reporting the measurements and QA/QC checks associated with mandatory GHG reporting in the USA.

Table 4-2. Comparison of reporting scope between EPA's GHGRP and CDP

	EPA Greenhouse Gas Reporting Program	CDP	Comment
Reporting requirements	- Monitor and report GHG emissions	- Monitor and report GHG emissions - Include climate change related risks, opportunities, strategies & performance)	- EPA's GHGRP supplements and complements other US government programs that may include CDP subject matter
Reporting responsibilities	- Facilities over 25,000 tonnes CO_2e - Suppliers report at the corporate level.	- At the corporate level (including the facilities they own, manage or operate)	- Information about GHG emissions from facilities is a subset of the information requested by CDP
Scope of reporting	- 41 industry sectors - Examples: stationary fuel combustion, electricity generation, industrial and chemical processing, - Petroleum and Natural Gas Suppliers of fuels, products and industrial gases.	- Same as EPA GHGRP, including combustion and fugitive emissions - Mobile source emissions	- CDP includes all of the activities covered by the EPA GHG RP and a few more
Reporting frequency	- Annually (calendar year)	- Annually (latest or more recent 12 month period for which data is reported)	- For CDP reporting could coincide with financial reporting

4.2 Uncertainty targets for mandatory GHG programs

With the emergence of new mandatory reporting regulations and emission reduction compliance obligations, new requirements are being promulgated for the accuracy of fuel flow measurements when such flows are used to quantify GHG emissions. A few prominent examples are provided below:

a. **California Air Resources Board (CARB) Mandatory GHG Reporting Regulations**. Flow measurement uncertainties are expected to be ±5% (CARB, 2012). The California requirements specifically apply to all GHGs emitted from petroleum refineries, hydrogen plants, and cogeneration plants.

b. **EU-ETS**. The European Union Emissions Trading System (EU-ETS) specifies a tiered approach for emission calculations together with required uncertainty ranges (EU-ETS MRG, 2007). It sets up a matrix of uncertainty requirements for different facility sizes and measurement approaches used. Table 4-3 provides an excerpt from the updated EU regulation specifying the rules for monitoring and reporting (EC, 2012). The regulation (Annex II, table 1) sets up tiers for maximum permissible uncertainty for activity data tiers. Facility owners or operators may apply a fallback monitoring methodology if they can demonstrate to the satisfaction of the regulatory authority that they can attain overall uncertainty thresholds for the annual level of GHG for the whole installation that do not exceed 7,5 % , 5.0% and 2.5% for category A, B, and C installations,[3] respectively.

The EU-ETS requirements are applicable to a limited set of petroleum and natural gas industry installations and track only CO2 emissions from fuel combustion and flaring. The requirement to quantify these sources within such tight uncertainty ranges is a reflection of the fact that these are the sources for which appropriate emission calculation methods are available, while they are also the largest emission sources and the key contributors to most installations[3] GHG emissions.

Table 4-3. EU regulation maximum permissible uncertainty for activity data tiers[a]

	Parameter to which uncertainty is applied	Tier 1	Tier 2	Tier 3	Tier 4
Combustion of fuels and fuels used as process input					
Commercial standard fuels	Amount of fuel [metric tons] or [Nm^3]	7.5%	5.0%	2.5%	1.5%
Other gaseous and liquid fuels	Amount of fuel [metric tons] or [Nm^3]	7.5%	5.0%	2.5%	1.5%
Solid fuels	Amount of fuel [metric tons]	7.5%	5.0%	2.5%	1.5%
Flaring	Amount of flare gas [Nm3]	17.5%	12.5%	7.5%	
Petroleum Refining (mineral oil refining)	Hydrocarbon feed [metric tons]				
Catalytic cracker, catalyst regeneration and flexi-cokers	Uncertainty requirements apply separately for each emission source (Total uncertainty of all emissions from a given source)	10.0%	7.5%	5.0%	2.5%
Hydrogen production		7.5%	2.5%		

[a] Excerpt from Table 1 of Annex II of the June 21, 2012 EU-ETS regulation.

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[3] For the EU-ETS: *Category A* installation, where average verified annual CO_2 emissions are equal to or less than 50,000 tonnes of CO_2e; *Category B* installation, where the average verified annual CO_2 emissions are more than 50,000 tonnes of CO_2e and equal to or less than 500,000 tonnes of CO_2e; *Category C* installation, where the average verified annual CO_2 emissions are more than 500,000 tonnes of CO_2e.

c. **EPA GHGRP**. The regulations governing the requirements for the GHG Reporting Program (GHGRP) in the USA. are included in many subparts to Part 98 in Title 40 of the Code of Federal Regulations (40CFR98). The rules are specified under general provisions along with sector-specific subparts that invoke the general provisions and add more requirements that are pertinent to specific industry sectors. General Provision §98.3 specifies that reporters must follow the procedures for emission calculation, monitoring, quality assurance, missing data, recordkeeping, and reporting that are specified in each relevant subpart.

In accordance with these provisions, flow meters and other devices that measure data used to calculate GHG emissions (e.g., GC analyzers used to determine composition data and flow meters used for calculations) must be calibrated by the date at which data collection is required to begin using a measurement device. All measurement devices must be calibrated according to a method specified either in a relevant subpart of the regulations in Part 98 or the manufacturer's recommended procedures, or an appropriate industry consensus standard.

Highlights of the calibration and maintenance requirements are provided in Table 4-4 below for all equipment and measurements used in association with applicable subparts to provide data for the GHG emission calculations. Subsequent recalibrations of the flow meters and other measurement devices must also be performed, as shown in Table 4-4. If no recalibration frequency is specified in the applicable subpart, the recalibrations must be performed at the frequency recommended by the manufacturer or as specified by an industry consensus standard practice.

Table 4-4. Highlights of calibration requirements under the EPA GHGRP

Activity	Applicability	Requirements	Methods	Calibration Error (CE)
Initial Calibration	- Meters that must be calibrated prior to commencing reporting: - Flow meters that measure liquid and gaseous fuel feed rates - Meters that measure process stream flow rates - Meters that measure feedstock rates - All other measurement devices (e.g., weighing devices)	- Flow meters used for reporting must meet applicable accuracy specification. - Exception: flow meters used to provide engineering estimates. - Calibrations should include measurement points within the normal meter operating range - For orifice, nozzle, and venturi flow meters: In-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters	- Calibration methods as in a relevant regulation subpart - Alternatively: - Manufacturer's recommended procedures - Appropriate industry consensus standard - The calibration method(s) used shall be documented in the written Monitoring Plan	- CE < 5% at each measurement point For differential pressure (delta-P), total pressure, and temperature transmitters, CE < 2% at each measurement point - Alternatively, the sum of the calculated CE values for the three transmitters < 6% at each calibration level
Maintenance and Recalibration	- Meters used to measure data used for calculation of GHG emissions - Requirements do not apply to any units where the rule allows for the use of "company records" to quantify fuel usage or other parameters - Fuel billing meters are exempted from the maintenance requirements if no common ownership with the fuel supplier	- In general, a primary element inspection (PEI) shall be performed at least once every three years - For petroleum refineries, flow meter shall be recalibrated: - At the minimum frequency specified by the manufacturer - Every two years - At the interval specified by the industry consensus standard practice used	- For continuously operated units and processes with infrequent outages: - The initial calibration may be postponed until the next scheduled maintenance outage - Subsequent recalibrations may also be postponed - Postponements should be documented in the facility Monitoring Plan	- Data from the flow meter shall be considered invalid if: - Initial calibration or a recalibration fail to meet the required accuracy specification - Invalidation begins with the first hour of the failed calibration - Invalidation continues until a successful calibration is completed

4.3 Tools for calculating uncertainty

A few reporting programs have developed tools to assist reporters in quantifying GHG emission uncertainty. Alternatively, general statistical methods or commercially available tools can also be used to evaluate uncertainty. A brief description of some common methods are provided below.

4.3.1 Numerical methods for calculating uncertainty

a. Monte Carlo Simulation

Monte Carlo simulation is a complex, model-based method for iteratively evaluating uncertainty associated with individual parameters. It applies to any probability distribution and may be the preferred approach where more complex equations are assessed, or where more than two correlated variables exist. It is one of many methods for analyzing uncertainty propagation where the goal is to determine how random variation, lack of knowledge, or error affects the sensitivity, performance, or reliability of the resulting emission inventory.

The principle of the Monte Carlo analysis is to generate random inputs from probability distributions of the respective variables and to calculate the corresponding emission values. This procedure is repeated many times using computer software, such as @RISK or Crystal Ball. The uncertainty model relies on repeated random sampling of all inputs and simultaneous recalculation of emissions (outputs) to measure variation over the course of numerous model iterations. The data generated from the Monte Carlo simulation can be represented as probability distributions (or histograms) or converted to error bars and confidence intervals.

Monte Carlo simulation can also be computationally intensive, with 10,000 simulations being the norm. A significant difficulty/barrier is the need to build a spreadsheet-based simulation model for uncertainty analysis that reflects the complexity of the emissions estimation model and allows generation of the variables required for the Monte Carlo simulation software.

Monte Carlo simulation has an advantage over uncertainty propagation in that one can specify multivariate distributions to account for correlations between different sources of uncertainty. Ideally, the distributions should be derived from data and knowledge of the underlying process. It is helpful in many instances to first graph the data, and then use the shape of the graph to determine the underlying distributions. The IPCC *Good Practices* document recommends choosing one of the following distributions: normal, lognormal, uniform, or triangular.[4]

It is then necessary to statistically test the hypothesis that the data follow a certain distribution. The test will vary based on the hypothesized distribution. For example, the Shapiro-Wilks test is often used to test if the data are normal or lognormal. Options to test for other distributions include Empirical Distribution Functions.

Selecting the proper probability distribution function for the model parameters may be difficult in light of inadequate data or a lack of understanding of the underlying physical processes. If there are not enough data to assume normality by the Central Limit Theorem (more than 30 data points), there are most likely not enough data to determine the underlying distribution of the data. Consequently, such analyses are often forced to rely on subject matter expert opinion to determine distributions rather than on observed data.

Once distributions are determined for all of the data sources, the Monte Carlo simulation will proceed by randomly sampling each of the distributions that describe the data used for estimating emissions. As many as 10,000 replicate samples are typically taken, with the total emissions being estimated for each replicate. These repeated determinations of emissions are used to generate a distribution of the total emissions with its mean being the estimate of total emissions, and its uncertainty determined by its variance.

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[4] The IPCC Good Practices document discusses how to perform Monte Carlo simulation in Section 6.2 (IPCC, 2000). It discusses choice of distribution in Section A1.2.5.

b. "Taylor" series expansion

The Taylor series expansion is an analytical method used to combine the uncertainty associated with individual parameters from a single scenario. It is a representation of a function as an infinite sum of terms that are calculated from the values of the function's derivatives at a single point. As a result, it provides a means of predicting the value of a function at one point in terms of the function value and its derivatives at another point.

This analysis involves the mathematical evaluation of the model equation. The statistical moments (mean, variance, skewness, etc.) for the model are calculated by expanding the model equation in a Taylor series about the means. The result of the expansion process is an equation for the overall model statistical moments, which is a function of the variable moments and the partial derivatives of the model equation. Online calculators exist for applying the Taylor series expansion.

Drawbacks associated with this type of analysis include:

- The numeric expansion may only be good for functions that are linear or nearly linear (unless many terms are used in the expansion).
- The method is strictly based upon calculations involving a parameter's statistical moments and does not directly incorporate the parameter's probability distribution (e.g., normal, lognormal, gamma).
- The expansion results only return an estimate of the statistical moments and not a distribution.
- Higher order estimates may be necessary to adequately address highly skewed distributions.
- The model may not be defined explicitly as a function of the input variables. As such, a Taylor expansion about the mean is not possible for these cases.

4.3.2 Examples of program-based tools

a. NGER Uncertainty Calculator

The *Australian National Greenhouse Gas and Energy Reporting (NGER)* requires that reporting entities provide a statistical estimate of the level of uncertainty associated with their entity's direct emissions with their annual GHG emission reports. The figures reported are used to assist the government in assessing uncertainty in the national greenhouse inventory that is prepared as part of Australia's commitments under the United Nations Framework Convention on Climate Change.

Technical guidance sets out how uncertainty is to be calculated, requiring reporters to identify uncertainty for each source of emission and each facility in order to arrive at uncertainty for the entire entity (Australian Government, 2009). The NGER guidance provides default parameter and aggregated uncertainties, per the examples in Table 4-5.

Table 4-5. Estimated uncertainty levels based on Australia National Greenhouse Gas and Energy Reporting (NGER)

	Fuels Combusted or Operations Performed	Uncertainty Level (%)[a]
FUELS COMBUSTION		
CO_2	Diesel oil; kerosene; fuel oil; heating oil	2
	Crude oil (including crude oil condensates); Liquid Petroleum Gas; jet fuel	3
	Natural gas if distributed in a pipeline; Coal Bed Methane or Coal Mine Waste Gas (if captured for combustion); compressed natural gas; unprocessed natural gas; Town Gas; Liquefied Natural Gas; gasoline	4
	Naphtha; black coal (other than used to produce coke)	5
	Coking coal	7
	Other natural gas liquids	9
	Ethane	10
	Petroleum coke; refinery coke; ethanol (for use as a fuel in an internal combustion engine); biodiesels	17
	Refinery gas and liquids; sludge biogas (if captured for combustion)	18
	Coke oven gas	19
CH_4 and N_2O	All Fuels	50
FUGITIVE EMISSIONS (including Flaring)	Oil and gas exploration, production, processing, transmission	50

a Note: The uncertainty estimates are from the 2006 IPCC Guidelines, volume 2.

The example uncertainty levels extracted from the NGER technical guidelines are those that are most relevant to the oil and natural gas industry based on common fuel use and operations. They are primarily applicable to simple calculation methods that use generic default emission factors. The data indicate that for such generic factors the default uncertainty percentages vary from fuel to fuel and by type of operation as a result of the assumed variable range of compositions and activity levels for each. Commercial liquid fossil fuels generally have a limited range of compositions, and therefore have a low associated uncertainty. Other self-generated fuels have higher default uncertainties due to variability in compositions.

For higher order emission estimation methods, which rely all or in part on site-specific measurements, the NGER guidelines recognize that the uncertainty associated with those estimates should reflect the uncertainty associated with the measured data that is the basis of the estimate, and not necessarily with the default assumptions listed in Table 4-5.

The Clean Energy Regulator (CER) developed an uncertainty calculator to assist NGER reporters that use higher order methods for estimating and reporting their emissions to this national program (CER, 2012). The calculations and factors incorporated in the calculators are in accordance with the NEGR 2008 regulations and the methodologies of Chapter 8 of the Technical Guidelines (Australian Government, 2009).

NGER requires reporting the level of uncertainty attributed to sampling and analysis variation at the 95% confidence level, and to report an assessment of the overall entity-wide uncertainty for its direct emissions (Scope 1). Reporters are not required to use the calculator, and can use any method for calculating uncertainty that complies with the regulatory requirements. The tool's calculations are based on the following assumptions:

- The estimated parameters are uncorrelated.
- Errors in each parameter are normally distributed.
- No biases exist.
- Individual uncertainties for each parameter must be less than 60% of the mean.

b. GHG protocol calculation tool

The GHG Protocol (WRI, 2011) has developed a spreadsheet-based tool that automates the aggregation steps associated with a basic uncertainty assessment for GHG inventory data. The GHG Protocol tool and guidance document are based on the IPCC Guidelines for National GHG Inventories. The tool aggregates uncertainty assuming a normal distribution of the variables using a first-order error propagation method. Use of this approach requires that the following assumptions are valid for the data set:

- The errors in each parameters must be normally distributed.
- There must be no biases (i.e., the estimated value is the mean value);
- The estimated parameters must be uncorrelated.
- The individual uncertainties in each parameter must be less than 60% of the mean.

If these assumptions are not valid for the data set, the Monte Carlo method can be used.

5. UNCERTAINTY CALCULATION OVERVIEW

Uncertainty is used to characterize the dispersion of values that could be reasonably attributed to a measured quantity. Uncertainty may be expressed as a qualitative ranking, such as the letter ratings assigned in EPA's AP-42 publication series (USA the EPA, 1currently has995 with Supplements through 2000), or as a quantified value. For the purpose of quantifying the uncertainty of a GHG inventory, this section first addresses measurement uncertainty, then discusses uncertainty associated with emission factors, and finally addresses the propagation of uncertainty. A step-by-step tutorial with examples of the uncertainty calculations is provided in Appendix F. The aggregation of uncertainty estimates for two example facility-based GHG emission inventories are provided in Appendices G and H.

Section Focus

This section provides an overview of general uncertainty calculation principles and more detailed guidance on the calculation methods that are applicable for defining single source uncertainties and for aggregating them at the facility (or entity) level. Uncertainty aggregation equations and an example are provided. Methods for reducing uncertainty are also addressed.

The subsections address:

- Measurement uncertainty
- Uncertainty propagation
- Uncertainty aggregation
- Reducing uncertainty

5.1 Measurement uncertainty

At the most basic level, a GHG inventory is comprised of estimated emissions from individual emission sources. For a given emission source, an emission estimate generally consists of an emission factor and some measure of the activity that results in the emission (referred to as the activity factor; see also Sections 2.3 and 2.4). Emissions from multiple sources are then aggregated to produce the inventory. The quantification of uncertainty should be applied at the emission source level (or grouping of similar emission sources) and then propagated to the total inventory (as discussed in Section 2.5).

Activity factors generally are a measured quantity, such as a count of equipment or measure of fuel consumed. Emission factors may be either based on site-specific measurements or based on published values that were derived from averaging a variety of measurements. Where measurements are used for either activity factors or emission factors, two components of uncertainty need to be considered: precision and bias.

5.1.1 Precision and bias

Precision, as defined by the API's MPMS (see Exhibit 1-1), is "the degree to which data within a set cluster together", which relates to the dispersion of the measurement values. A method may produce results that are not very precise (having highly dispersed observations), but result in a good estimate on average, as shown in Figure 5-1. The variability or precision associated with such an estimate will decrease as more data points are collected.

Bias, on the other hand, refers to how accurately a method estimates the true value. An example of bias would be a meter that is not calibrated correctly and consistently overestimates the measurement. Ideally, the data measurement scheme should be designed in a way to minimize bias. For example, if the measuring device is well maintained and calibrated to minimize drift, there may be no bias in the measurement.

Figure 5-1 shows an example of the error of an unbiased measurement over time, where the errors are centered around zero. When these measurements are aggregated, some of the positive errors are offset by some of the negative errors, resulting in a lower estimate of uncertainty for the aggregate measurement.

Figure 5-2 shows an example of the error in a biased measurement over time. Similar to the unbiased case in Figure 5-1, some of the high errors are offset with some of the low errors so the uncertainty in the precision of the estimate is lower for the aggregate. However, in Figure 5-2, the errors are not centered on zero as in Figure 5-1; they are centered on five. This means that there is a bias in the estimate. Unlike precision, the

Figure 5-1. Measurement error over time of an unbiased estimate

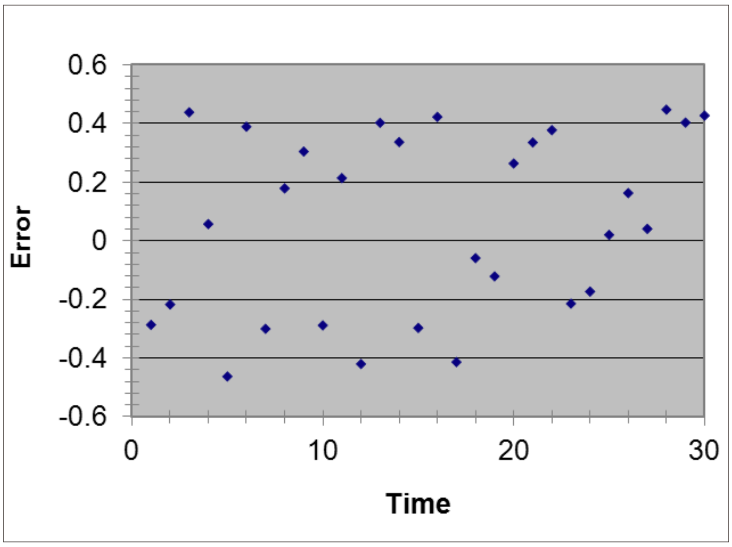
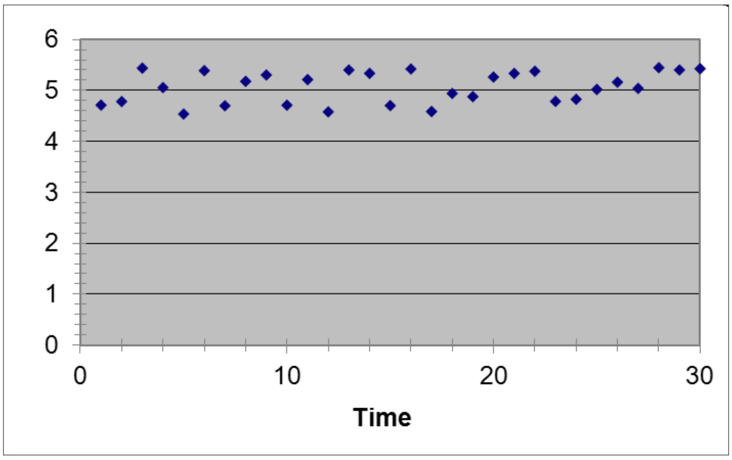


Figure 5-2. Measurement error over time of a biased estimate



uncertainty due to the bias generally does not decrease as more data points are collected. Thus, precision and bias should be considered separately, if possible.

If bias can be quantified, it should be corrected and thus eliminated from consideration in quantifying uncertainty. For example, if a fuel stream has two types of measurement devices, data can be collected from both devices to check for agreement. A bias would be indicated if the measurements differed. However, quantifying and correcting for bias might not always be practical since it often requires application of frequent calibration routines and implementation of quality control procedures that would allow instrument adjustments and/or corrections under prescribed conditions. It will also require proper quantification routines that account for drift or other causes of bias between calibrations on an ongoing basis.

The general approach for quantifying bias would depend on prior experience in the laboratory or from specifically designed field measurement campaigns. Measurement bias can vary from small to very large, depending on the application, and can even change over time if the measurement instrument is allowed to drift without calibration. Therefore, in practice, bias will most commonly be determined using expert judgment and will be based on such parameters as the length of time since the equipment was calibrated and other factors that would cause the measurement to systematically overestimate or underestimate the true value.

5.1.2 Confidence intervals

Uncertainty is commonly expressed in terms of confidence intervals, where the confidence intervals establish the lower and upper tolerances associated with an estimated number. Expressed as an absolute value, the confidence interval is computed as:

$$\pm t \times \frac{s}{\sqrt{n}}$$

(Equation 5-1)

Where:

s = standard deviation;

n = sample size; and

t = t-value for "n-1" degrees of freedom

And

$$s = \sqrt{\frac{1}{n-1}\sum_{i=1}^{n}(x_i - \overline{x})^2}$$

(Equation 5-2)

Where:

x_i = the ith observation in the data set and

$\overline{x}$ = the mean of the data set.

$$\overline{x} = \frac{\sum_{i=1}^{n} x_i}{n}$$

(Equation 5-3)

Tables for the Student's t-distribution can be found in most basic statistics references. Most spreadsheet software programs have a function that will calculate the necessary t-value. This is the preferred method since the software generally retains more significant digits for the t-value than a look-up table would display.

5.1.3 Implementation of Pedigree Matrix approach

The Pedigree Matrix could be a useful tool when measured single parameter uncertainties are unknown. This approach may be used to elicit a structured expert's judgment for determining single parameter uncertainty values, which can then be propagated using techniques such as series expansion or Monte Carlo simulations, as discussed below.

In the pedigree matrix approach, qualitative data quality assessment is used to select appropriate uncertainty scaling factors for single parameters. Assessment of data quality should be conducted separately for activity data and emission factors, which will be merged in the ensuing uncertainty propagation analysis.

In this proposed adaptation, which is based on guidance provided by the GHG Protocol (WRI/WBCSD a, 2011), an uncertainty scaling factor is selected by assigning a data quality score (very good, good, fair and poor) to each of five data quality indicators (precision, completeness, temporal geographical and technological representativeness). The ranges of recommended uncertainty scaling factors are shown in Table 5-1 and represent the contribution to the square of the geometric standard deviation.

Table 5-1. Example of Pedigree Matrix for determining uncertainty scaling factors based on data quality ratings[a]

Indicator score	Very good	Good	Fair	Poor
Precision	1.00	1.10	1.20	1.50
Completeness	1.00	1.05	1.10	1.20
Temporal Representativeness	1.00	1.10	1.20	1.50
Geographical Representativeness	1.00	1.02	1.05	1.10
Technological Representativeness	1.00	1.20	1.50	2.00

[a] Weidema and Wesnaes, 1996

Data sources used when compiling the emissions inventories need to be assessed. The total uncertainty, expressed as a 95% confidence interval, SDg_{95} (the square of the geometric standard deviation), is calculated using the formula shown below (WRI/WBCSD a, 2011):

$$SDg_{95} \cong \sigma^2 = exp\sqrt{(\ln U1)^2 + (\ln U2)^2 + (\ln U3)^2 + (\ln U4)^2 + (\ln U5)^2 + (\ln Ub)^2}$$

(Equation 5-4)

Where:

U_1 = uncertainty factor of precision
U_2 = uncertainty factor of completeness
U_3 = uncertainty factor of temporal representativeness
U_4 = uncertainty factor of geographic representativeness
U_5 = uncertainty factor of other technological representativeness
U_b = basic uncertainty factor

In addition to the uncertainty factors for the data quality categories, one has to include basic uncertainty factors for the kind of input considered. Examples of applicable basic uncertainty factors that are pertinent to addressing GHG emissions uncertainty are provided in Table 5-2. An example application of this approach is provided in Section 5.3.2.

Table 5.2. Basic Pedigree Matrix uncertainty factors for selected pollutants[a]

Indicator score	Very good	Good
CO_2	1.05	1.05
CH_4	1.50	Not available
$N0_x$ N_20	1.50	1.40
NMVOC total	1.50	1.50
NH_3	1.50	1.20
Individual Hydrocarbons	1.50	2.00

[a] Overview and Methodology, Data v2.0 (2007). Ecoinvent Report No. 1, Dübendorf, December 2007. http://www.ecoinvent.org/fileadmin/documents/en/01_OverviewAndMethodology.pdf

5.2 Overview of uncertainty propagation

Uncertainty propagation involves mathematically combining individual sources of uncertainty to establish an estimate of the overall uncertainty. Specific uncertainty propagation techniques are discussed in Section 5.2.1.

The following three assumptions are important when applying the uncertainty propagation technique for overall uncertainty assessment (IPCC, 2000: Annex 1, section A1.4.3.1):

1. The uncertainties are relatively small, which is defined as the standard deviation divided by the mean value being less than 0.3.
2. The uncertainties have Gaussian (normal) distributions.
3. The uncertainty values (i.e., the errors or uncertainties associated with the measured data or reported values) are mutually independent.

In many cases, the first assumption may be difficult to meet. For example CH4 and N2O emissions often have very sparse data and large associated uncertainties. Conducting a Monte Carlo simulation (discussed further in Section 4.2.3) is an option if the standard deviation divided by the mean is greater than 0.3. However, Monte Carlo simulations require a significant level of detail for the description data to characterize the probability distributions. Without such information, the potential error introduced from incorrectly specifying the distributions for a Monte Carlo simulation could outweigh the potential error that might be associated with applying an uncertainty propagation technique for sources with large uncertainties. Therefore, this document suggests that the first assumption can be relaxed for emission estimates with a small overall contribution to the GHG inventory. Through the propagation of uncertainty for all emissions in the inventory, the impact of small emission sources with large uncertainties can be evaluated relative to the entire inventory. This evaluation can be used to identify and prioritize emission sources that require more data to reduce the overall uncertainty of the inventory.

The second assumption is based on the normality of the distribution of the underlying source data (i.e., symmetrical around the mean). According to the Central Limit Theorem, for a large enough sample size (n>30), we can relax the normality assumption but still assume that the sampling distribution of the sample means is normally distributed (Casella and Berger, 1990). Hence, if the calculated uncertainty is based on statistical sampling of the population, one would need to obtain more samples to approach normality. Alternatively, we might consider data transformation, i.e., mathematically transforming the data to a different scale and using that transformed 'normal' distribution to derive the 95% confidence interval. For example, in the case where the data distribution is skewed and the uncertainty is >100% of the mean (i.e., where the lower limit would be less than zero), the data could be transformed to a lognormal distribution. This approach, however, requires the confidence interval to be transformed back to the original scale to express the uncertainty in the original units, which can introduce error. As a result, there is a trend away from using transformational approaches due to issues in transforming the data back to their original scale.

The third assumption states that there is no significant covariance between the uncertainties that are to be combined, which is equivalent to saying that the errors or uncertainties are independent or that there is no correlation between the uncertainty terms. The uncertainties in two quantities would be considered independent if they were estimated by entirely separate processes and there were no common source of uncertainty. The uncertainties in two quantities would be dependent if they had a common source of uncertainty (Williamson *et al*, 1996).

Covariance between two uncertainty terms can be addressed through an additional term in the uncertainty propagation equations (discussed further in Section 4.2.2). However, the IPCC Good Practices document suggests avoiding the need for the covariance term in the equation by "…stratifying the data or combining the categories where the covariance occurs" (IPCC, 2001).

5.2.1 Propagation equations

Four general equations for propagating uncertainty are used in this document and the API Compendium for compiling the uncertainty associated with a GHG inventory. A general introduction to the equations is presented here, with example applications provided in Appendix F.

Consider two quantities that can be measured: X and Y. The uncertainty for these values can be expressed on an absolute basis as $\pm U_x$ and $\pm U_y$ respectively, where U is calculated through statistical analysis (as represented by Equation 5-1), determined through the Monte Carlo technique, or assigned by expert judgment. Uncertainty may also be expressed on a relative basis, generally reported as percentage:

$$\pm 100\left(\frac{U_X}{\mathrm{X}}\right)\%\,\mathrm{or}\pm 100\left(\frac{U_Y}{\mathrm{Y}}\right)\%\,\mathrm{respectively}$$

Depending on the uncertainty propagation equation, the absolute or relative uncertainty value may be required. In addition, selection of the propagation equation also depends on whether the uncertainties associated with the individual parameters are independent or correlated.

a. Uncertainty propagation for a sum (or difference)

Two potential equations are used for computing the total uncertainty from the addition or subtraction of two or more measured quantities. The selection between the two equations depends on whether the uncertainties associated with the measured quantities, X and Y, are correlated.

For uncertainties that are mutually independent, or uncorrelated (i.e., the uncertainty terms are not related to each other), the aggregated uncertainty is calculated as the "square root of the sum of the squares" using the absolute uncertainties, as shown in Equation 5-5.

$$U\left(abs\right)_{X+Y+\ldots N} = \sqrt{U_X^2 + U_Y^2 + \ldots + U_N^2}$$

(Equation 5-5)

Where:

U(abs) = the absolute uncertainty.

The absolute uncertainty values are used in the equations, and the resulting aggregated uncertainty ($U_{X+Y+\ldots+N}$) is also on an absolute basis. Note that where a constant is also included in the emission estimation calculation, the absolute uncertainty should include the constant. This is demonstrated in the example provided in Appendix F.

For two uncertainty parameters that are related to each other, the equation becomes:

$$U\left(abs\right)_{CorrelatedX+Y} = \sqrt{U_X^2 + U_Y^2 + 2r(U_X \times U_Y)}$$

(Equation 5-6)

Where:

r = the correlation coefficient between U_X, U_Y, (discussed further in Sections 5.2.3 and Appendix F).

However, the IPCC *Good Practices* guidance states, "Once the summation exceeds two terms and the covariance occurs, the use of the Monte Carlo approach is preferable where data resources are available" (IPCC, 2000).

b. Uncertainty propagation for a product (or quotient)

The equation for propagating uncertainties from the product or quotient of two or more measured and independent quantities is similar to Equation 5-5. However, in this case the relative uncertainties are used, as shown in Equation 5-7. When multiplied by 100, the resulting combined uncertainty ($U(Rel)_{XxYxN}$) is expressed as a percentage.

$$U\left(rel\right)_{X\times Y\times\ldots\times N} = U\left(rel\right)_{X\div Y\div\ldots\div N} = \sqrt{\left(\frac{U_X}{X}\right)^2 + \left(\frac{U_Y}{Y}\right)^2 + \ldots + \left(\frac{U_N}{N}\right)^2}$$

(Equation 5-7)

Equation 5-7 is used to estimate the uncertainty of a product or quotient of two parameters (X and Y) where the uncertainties are correlated and positive values. Here also, relative uncertainty values are used in the equation and the resulting combined uncertainty is on a relative basis.

$$U(rel)_{Correlated X \times Y} = \sqrt{\left(\frac{U_X}{X}\right)^2 + \left(\frac{U_Y}{Y}\right)^2 + 2r\left(\frac{U_X}{X} \times \frac{U_Y}{Y}\right)}$$

(Equation 5-8)

c. Combining uncertainties

It may be necessary to combine multiple uncertainty parameters associated with a single measured value, such as combining uncertainties for precision and bias. For uncertainty parameters that are independent, the combined uncertainty is calculated using the absolute uncertainties as shown in Equation 5-5. Similarly, for uncertainty parameters that are related to each other, Equation 5-6 applies.

5.2.2 Comparison of uncertainty propagation and Monte Carlo

Section 6.3.1 of the IPCC *Good Practices* document compares the uncertainty propagation method and the Monte Carlo simulations (IPCC, 2000). It notes that the uncertainty propagation method's assumption of normality leads to symmetric 95% confidence intervals whereas the Monte Carlo method can take into account the fact that emissions are bounded below by zero to fit an asymmetric (and thus narrower) confidence interval. If the data are skewed and one transforms the data (discussed earlier), one could achieve the asymmetric confidence intervals using uncertainty propagation, as well.

Since the Monte Carlo simulations can assume a truncated distribution, the lower confidence limits tend to be closer to the mean than the upper confidence limits. The IPCC *Good Practices* document goes on to state that the two methods produce results that are fairly comparable. It recommends that countries report the results of the uncertainty propagation method and those countries with "sufficient resources and expertise" report Monte Carlo results as well.

These guidelines concentrate solely on the uncertainty propagation method due to the potential to introduce further errors in assigning the probability distributions for the Monte Carlo simulations. As stated previously, applying the uncertainty propagation methods, even where the assumptions are not met, is advised in these guidelines, particularly for emission sources with a small contribution to the overall GHG inventory. As data collection methods improve for GHG inventories, the ability to quantify uncertainties will also improve.

5.2.3 Correlation coefficient

The correlation coefficient, r, used in Equations 5-5 and 5-7, is a number between -1 and 1 that measures the linear relationship between the errors or uncertainties of two measured parameters. The value of r is zero when the parameters are independent. As stated previously, once the uncertainty propagation exceeds two terms and covariance occurs, the use of the Monte Carlo approach (described further in Section 4.0) is preferable (IPCC, 2001). Additional details on calculating the correlation coefficient are provided in Appendix F. A simplified explanation follows.

For two terms that might be correlated, the errors or uncertainties are plotted against each other. For the purpose of this discussion, Ux represents the uncertainties of one variable plotted along the x-axis, and Uy represents the uncertainties of the second variable plotted on the y-axis. The correlation coefficient, r, is determined by a linear regression of the U_x and U_y values.

If one suspects that the uncertainty parameters are correlated, but data are not available to plot or calculate the correlation coefficient, the following rule-of-thumb values could be applied using expert judgment (Franzblau, 1958):

- r = 0: no correlation, the data are independent
- r = ±0.2: weak correlation
- r = ±0.5: medium correlation
- r = ±0.8: strong correlation
- r = ±1: perfect correlation, the data fall on a straight line.

5.3 Uncertainty aggregation examples

The following sections provide examples for aggregating emissions.

5.3.1 IPCC aggregation template

IPCC provides an example calculation table for estimating the aggregated uncertainty of GHG emissions, which is based on the error propagation method for the multiplication of an emission factor and activity value (IPCC, 2006, page 3.31). The approach entails the multiplication of an emission factor and activity value, and their associated uncertainties, so they can be aggregated across source categories. WRI has also developed a simple spreadsheet tool that applies these calculations (WRI/WBCSD b, 2011).

Table 5-3 exhibits a generic template that is an adaptation of the IPCC-recommended approach for calculating aggregated uncertainties. This template could be tailored for specific oil and natural gas inventories by expanding or collapsing the emission sources and industry segments included based on the goals of the assessment and data availability.

Table 5-3. Adapted IPCC Template: Approach for Aggregating Uncertainty

	A	B	C	D	E	F	G	H	I
Gas Industry Segment	**Activity Data (e.g. Quantity of fuel used)**	**Activity Data Units**	**Activity data Uncertainty**	**GHG emission factor**	**Emission Factor Units**	**Emission Factor Uncertainty**	**Emissions in tonnes**	**Emissions in tonnes CO_2e**	**Uncertainty of Calculated Emissions (expressed in ± Percent)**
			±%			±%	$A \times D$	$G \times GWP$	$1=\sqrt{C^2+F^2}$
CO_2									
Onshore Production									
Offshore Production									
Natural Gas Processing									
CH_4									
Onshore Production									
Offshore Production									
Natural Gas Processing									
TOTAL								$\sum H$	$=\frac{\sqrt{\sum_{i=1}^{n}\left(\frac{l_n}{100}\times Hn\right)^2}}{\sum H}\times 100\%$

Table 5-4 provides an example using such a table structure for calculating uncertainty, similar to the IPCC table and WRI tool. This example illustrates the aggregation of uncertainty for the combined CO_2 and CH_4 emissions from combusting natural gas. Equations 5-6 and 5-4 are applied, assuming that the variables are uncorrelated. More detailed examples are provided in Appendices F and G.

Table 5-4. Example uncertainty calculation and reporting table

Emission Source Description: Example for Natural Gas Combustion	A	B	C	D	E	F	G	H	I
	Activity Data (e.g. Quantity of fuel used)	Activity Data Units	Activity data Uncertainty	GHG emission factor	Emission Factor Units	Emission Factor Uncertainty	Emis-sions in tonnes	Emissions in tonnes CO_2e	Uncertainty of Calculated Emissions (expressed in ± Percent)
			±%			±%	$A \times D$	$G \times GWP$	$1 = \sqrt{C^2 + F^2}$
CO_2 Emission	3000	MMBtu/ yr	+/- 5.0%	0.0732	tonnes CO_2/ MMBtu	+/- 10.0%	219.6	219.6	11.2%
CO_4 Emission	3000	MMBtu/ yr	+/- 5.0%	$3.01\text{x}10^{-6}$	tonnes CO_4/ MMBtu	+/- 15.0%	0.009	0.19	15.8%
TOTAL								$\sum H$	$= \dfrac{\sqrt{\sum_{i=1}^{n}\left(\frac{l_n}{100} \times Hn\right)^2}}{\sum H} \times 100\%$
								219.79	$= \dfrac{24.59}{219.79} \times 100\% = 11.2\%$

Table 5-5. Pedigree Matrix example

Indicator	Example Application	Indicator Score
Precision	The precision for the volume of gas combusted is good since the flow meter is calibrated annually. The precision for the composition of the gas is good since the gas suppliers follow industry specifications to measure gas composition. Formal verification is not conducted on either flow or composition measurements.	Good: 1.10
Completeness	The flow and composition measurements are specific to the natural gas that is combusted. The CH_4 emission factor associated with the compressor is based on industry data, but this is considered below.	Very good: 1.0
Temporal representativeness	Recent flow measurements and composition data are applied. The CH_4 emission factor for the compressor is accounted for below.	Very good: 1.0
Geographical representativeness	The flow rate and composition data are for the example compressor. The CH_4 emission factor is based on compressors used in theUSA, but is considered fair.	Very good: 1.05
Technological representativeness	The flow rate and composition data are for the example compressor.	Very good: 1.0
CH_4 Combustion emissions	From Table 5-2. This rating accounts for the use of a default combustion emission factor.	1.50

5.3.2 Pedigree Matrix example

Table 5-5 provides an example application of the Pedigree Matrix approach for determining the uncertainty associated with CH_4 emissions from the combustion of natural gas in a compressor. For this example, the amount of fuel combusted is metered, and the meter is calibrated annually. The natural gas is purchased from a local distribution company.

The uncertainty, expressed as a 95% confidence interval, is calculated by applying Equation 5-4 and using the uncertainty factors from Table 5-5.

$$SDg_{95} \cong \sigma^2 = exp^{\sqrt{(lnU1)^2+(lnU2)^2+(lnU3)^2+(lnU4)^2+(lnU5)^2+(\ln Ub)^2}}$$

$$= exp^{\sqrt{(ln1.1)^2+(ln1.0)^2+(ln1.0)^2+(ln1.05)^2+(ln1.0)^2+(ln1.5)^2}}$$

$$SDg_{95} = 1.52$$

The 95% probability range for this example would be expressed as (median/SDg_{95}) to (median* SDg_{95}). Hence, for this example, if the median CH_4 emissions are 5,000 tonnes per year the 95% probability range would be 3,290 to 7,600 tonnes per year.

5.3.3 Uncertainty assessment from API Technical Report 2571

Table 5-6 provides an illustration for performing the uncertainty assessment in conjunction with the equations and processes set forth in the TR 2571 document, using average values as an example.

Table 5-6. Example of flow measurement total uncertainty[a]

Component	Units	Nominal Value	Standard Uncertainty	Standard Uncertainty (Ux)%	Sensitivity Coefficient (Sx)	Total Uncertainty $(U_x \times S_x)^2$
Unit Conversion Factor	NA	1.899	0.0	0.0000	1.00	0.000
Discharge Coefficient	Dimensionless	0.6008	0.00411	0.6834	1.00	0.467
Expansion Factor	Dimensionless	0.9989	0.00014	0.0144	1.00	0.000
Bore Diameter	Inches	0.5	0.0004	0.0750	2.04	0.023
Pipe Diameter	Inches	2.067	0.0257	1.2425	0.04	0.002
Base Compressibility	Dimensionless	0.9979	0.0010	0.1000	1.00	0.010
Base Temperature	°Fahrenheit	60	0	0.0000	1.00	0.000
	°Rankine	519.67				
Flowing Pressure	psia	100	0.46	0.4575	0.5	0.052
Universal Gas Constant	ft-lbf/lbmol-°R	1545.33	0	0.0000	0.5	0.000
Gravitational Constant	lbm-ft/lbf-s_2	32.174	0	0.0000	1.00	0.000
Differential Pressure	Inches-H_2O	10	0.1120	1.1204	0.50	0.314
Base Pressure	psia	14.73	0	0.0000	1.00	0.000
Molecular Weight	lbm/lb-mol	16.799	0.1260	0.7500	0.50	0.141
Flowing Compressibility	Dimensionless	0.98664	0.007	0.7500	0.50	0.141
Flowing Temperature	°Fahrenheit	60	2.598	0.5000	0.50	0.063
	°Rankine	519.67				
Installation Effect Factor	Dimensionless	1	0.02	2.0000	1.00	4.000
Meter Condition Factor	Dimensionless	1	0.02	2.0000	1.00	4.000
Energy Content	Btu/ft³	1050	7.88	0.7500	1.00	0.563
Carbon Content[b]	lbm/ft³	0.035	0.0002625	0.7500	1.00	0.563
SUMMARY						
Volume Flow Rate	SCFH	848		Total Volume Uncertainty		3.04
Energy Flow Rate	Btu per hour	890,320		Total Energy Uncertainty		3.13
Carbon Flow Rate	Tons per hour	0.015		Total Carbon Uncertainty		3.13

[a] Extracted from API TR 2571, Table A.3.5

[b] Carbon Content is the fraction of carbon in the fluid expressed as percent by weight.

The example in Table 5-6 assumes a 2 in. line with a 0.5 in. orifice plate using a multivariable transmitter for measuring temperature, pressure, and pressure differential (DP). It also assumes that the gas composition is measured at the fuel gas drum by an online analyzer; hence lower molecular weight uncertainty values are used.

The total uncertainty was derived by summing the individual combined uncertainties (U_x × S_x)2 and taking the square root of the sum. The calculation for this example is done three different ways to derive three different uncertainties (volume, energy, and carbon).

- ***Volume Uncertainty:*** all components are included with the exception of energy content and carbon content;
- ***Energy Uncertainty:*** all components are included with the exception of the carbon content;
- ***Carbon Uncertainty***: all components are included with the exception of the energy content.

5.4 Strategic reduction of uncertainty

5.4.1 Periodic updates

Activities data that comprise a GHG emission inventory will likely change from year to year. Emission factor information may also vary over time. However, aspects that impact the calculation of uncertainty such as measurement equipment or techniques, quantification methods, and emission factors, are relatively constant year-on-year. Therefore, it may not be necessary to conduct an uncertainty assessment on an annual basis. A frequency of every three to five years may be sufficient, but should ultimately be determined based on the variability of the factors that contribute to the quantification of uncertainty.

5.4.2 Reducing uncertainty of emission estimates

This section addresses the potential need to refine the emission inventory to reduce the uncertainty in the overall emission estimate. There may be several reasons to do this. In some specific locations, there may be state or national regulations, or guidelines for voluntary programs that suggest or require an emission inventory to have uncertainties lower than a certain percentage level. A company may also independently wish to refine its own uncertainty limits, if it considers the uncertainties too large.

The reader should note that none of the strategies mentioned here are aimed at reducing the actual emissions of GHGs. That is a separate subject, and while emission reductions are achievable in some cases, they are beyond the scope of this report. This section focuses on reducing the mathematical and statistical uncertainty associated with an existing emission inventory.

Once a decision has been made to refine and reduce the uncertainty associated with a given emissions inventory, some strategic analysis of the major sources contributing to the uncertainty is in order. It is important to know which emission sources and which uncertainties significantly contribute to the overall inventory uncertainty. It would make little sense to refine a term with large confidence bounds, but that contributed very little to the overall inventory uncertainty. It may also be useful to have a target uncertainty in mind. For example, if the current total uncertainty is ±50.0 % and the company wishes to reduce it to ±25.0%, then that target is useful in the analysis. As uncertainties of individual values in the calculations are examined, values that have uncertainties that are already at or below the 25.0% target, are less likely to be fruitful targets for reduction. The goal is to find the largest contributors to emissions that have the largest uncertainties.

The largest contributors to uncertainty can be determined by multiplying the emission estimate by the maximum error bound for each source. This would result in the upper bound emission estimate for the particular source. The emission estimates can then be sorted by the largest contributors. This is demonstrated in Table 5-7 on page 59 for the example crude oil production facility presented in Appendix G.

a. **Onshore oil field**

    Each facility should examine the major categories of emissions and emission uncertainty, and then examine specific emission sources within the category. Prioritizing the largest sources of uncertainty can be done with this simple approach.

    Figure 5-3 illustrates emissions for the facility with each emission category and each gas converted to CO_2e, using each gas' GWP. It should be noted that although the GWP itself has uncertainty associated with it, this report treats the

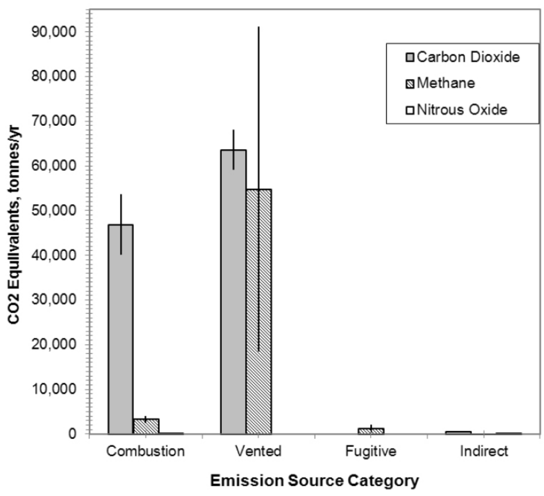
Table 5-7. Emission uncertainty ranking for onshore oil production example

Source Type	Source	Emissions (tonnes CO_2e /yr)	Maximum Uncertainty, %	Maximum Uncertainty, (tonnes CO_2e /yr)	Ranking
Combustion Sources	Boiler/heaters	5,210	8.77	457	9
	Natural gas engines	14,100	15.6	2,200	6
	Diesel engines	220	15.5	34	
	Flares	30,700	21.1	6,478	3
	Fleet vehicles	129	19.2	25	
Vented Sources	Dehydration and Kimray pump vents	5,440	76.0	4,134	4
	Tanks-flashing losses	40,300	88.7	35,746	1
	Amine unit	66,700	9.77	6,517	2
	Pneumatic devices	3,360	49.2	1,653	7
	Chemical injection pumps	2,530	106	2,682	5
	Vessel blowdowns	3.65	319	12	
	Compressor starts	38.7	187	72	10
	Compressor blowdowns	17.3	175	30	
	Well workovers	0.939	294	3	
	Other non-routine (PRVs)	6.81	319	22	
Fugitive Sources	Fugitive components	1,100	83.3	916	8
	Fleet vehicle refrigeration, R-314a	1.30	112	1.5	
Indirect Emissions	Electricity consumed	553	10.2	56	

GWP as a selected constant. Therefore, no uncertainty is associated or propagated from the GWP values. Figure 5-3 also illustrates the bounds of uncertainty (at 95% confidence) for each emission source category.

Among the major types of emissions in Figure 5-3, are three very significant emission categories: vented sources of CO_2; vented sources of CH_4; and combustion sources of CO_2. These are the most significant source of greenhouse gas emissions for this facility. Together they comprise almost 95% of all GHG emissions from the facility. Examination of the uncertainties, as shown in the bars on Figure 5-3, or the absolute uncertainty values in Table 5-7, shows that vented emissions of CH_4 from tank flashing losses are the most significant source of uncertainty, contributing 35,746 CO_2e tonnes of uncertainty (based on 40,300 ±88.7% CO_2e tonnes). Carbon dioxide vented from the amine unit is the next largest source of uncertainty, contributing 6,517 CO_2e tonnes of uncertainty. The third largest source are emissions from flares, with 6,478 CO_2e tonnes of uncertainty.

Figure 5-3. Onshore oil field: summary of co2 equivalent emissions and uncertainties



Therefore, should the company wish to reduce uncertainty in the GHG emission inventory from this onshore oil field facility, these categories would be the primary targets for uncertainty reduction. These appear to be the sources where uncertainty reduction efforts could be effectively undertaken to refine the inventory and reduce the uncertainty.

b. Vented sources

Within vented emissions, are 10 sources listed in Table 5-7. The highest ranking source, tank flashing losses, contributes a significant part of the vented emissions (34% of total vented emissions), as well as the majority of the uncertainty for the entire facility. That single category source's uncertainty is 1,700 tonnes of methane, or about 35,700 tonnes of CO_2e. Therefore, improvement of this estimate could greatly reduce uncertainty in the overall inventory.

Examination of the detailed calculation for that category (presented in Section G.7), shows that the largest uncertainty is in the emission factor, which is a general industry-wide emission factor. The uncertainty in that factor is ±90.4%. This uncertainty can be reduced simply by using an improved estimation method to determine tank flashing losses.

As elaborated in the API *Compendium*, other emission estimation methodologies can be used to estimate tank flashing emissions with lower uncertainties. For example, if the "EUB Rule of Thumb" approach (API Compendium Section 5.4.1, 2009) were applied instead of the default tank flashing emission factor for the example onshore production facility, the emissions for this category would be 20,500 ±49.7% tonnes CO_2e.[5] This one revision would change the overall inventory emissions to 151,000 ±9.88% tonnes CO_2e.

The second largest source of uncertainty for this facility is emissions from amine units. Here also, a default emission factor was applied with an uncertainty of 119% (refer to Section G.8). Emissions from this source could be estimated more accurately by applying a mass balance approach or utilizing a process model, such as AMINECalc (API, 1999). Although published uncertainty values are not available for these methods, expert judgment would suggest these methods are more accurate than the default emission factor.

c. Combustion CO_2

If the company decided to take the next step of emission reductions, it may target the next largest category of uncertainty. As shown in Table 5-7, emissions from boilers/heaters, natural gas engines and flares are ranked in the top ten highest emission sources, with flares contributing the largest uncertainty for the combustion sources. Uncertainty associated with flares was calculated to be 21.1%, or about ±6,500 tonnes CO_2e/yr.

By examining the calculations used to estimate flaring emissions (refer to Section G.4), the following general strategies could be selected by the operating company to reduce uncertainty in flaring:

- Refine the measurement of total gas flared (the activity factor), to reduce the activity factor uncertainty from the current value of 15%; and/or
- Refine the gas composition measurements to reduce the uncertainty from 4%.

Refining the measurement of total gas flared may result from many approaches, such as improving the meter quality (even possibly replacing the meter); improving the quality control of the existing meter (such as number of calibrations and inspections); or improving the number of measurements taken and recorded from the meter that is used to calculate the total gas flared (this assumes measurements were not already continuous). These approaches have varying costs, and some may be cost-prohibitive. The company would have to determine which approach is the most cost effective.

Refining the gas composition data may also come from several methods, such as taking additional routine samples, installing a continuous gas analyzer, or using a better analysis method. As with the gas flow rate measurement, these approaches have varying costs, and some may be cost prohibitive. The company would have to determine which approach is the most cost effective.

If the company is effective in reducing the uncertainty in flare gas CO_2 emissions, it might then elect to proceed to the next largest uncertainty source. The end-user will have to recalculate total emissions for the company or facility each time, and determine if the uncertainty goal or target has been reached.

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[5] This emission estimate is based on an assumed separator pressure of 30 ±5% psi, and an assumed uncertainty of ±50% applied to the correlation constant used in API *Compendium,* Equation 5-20.

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IPIECA is the global oil and gas industry association for environmental and social issues. It develops, shares and promotes good practices and knowledge to help the industry improve its environmental and social performance, and is the industry's principal channel of communication with the United Nations.

Through its member-led working groups and executive leadership, IPIECA brings together the collective expertise of oil and gas companies and associations. Its unique position within the industry enables its members to respond effectively to key environmental and social issues.

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The American Petroleum Institute is the primary trade association in the United States representing the oil and natural gas industry, and the only one representing all segments of the industry.

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