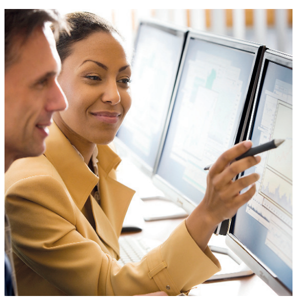
Petroleum industry guidelines for reporting greenhouse gas emissions

Second edition

Climate change
2011

Legal note

This voluntary guidance document is designed to serve as a resource for interested companies; the guidance provided by this work does not establish an industry standard as to the nature of a company's public reporting practice. The recommendations in these *Guidelines* on how to report on a particular issue are addressed to those companies who choose to include that issue in their voluntary greenhouse gas (GHG) emissions reporting, and terms such as 'the reporting company should …' are to be understood in this sense.

The terms and definitions used in this document are not necessarily the same as terms and definitions used in various statutes, rules, codes or other authoritative legal documents. Users and readers of this document should refer to relevant legal sources or consult their own legal counsel for explanations as to how the terms and definitions used in this document may differ from the legal terms and definitions used in their particular areas of operation. It should not be implied that the guidance in this document is required to be followed for any national, local or other law. Furthermore, it is not intended to serve as a substitute for existing public reporting requirements and regulations. Any company reporter that has a question as to whether or not reports that follow the information contained herein will meet any specific reporting requirements applicable to their particular operations should consult with the reporter's own legal counsel.

A cautionary note regarding performance indicators

Aggregated, company-level, non-financial performance data, developed using these *Guidelines*, can be informative for comparing relative performance among different companies, such as benchmarking GHG emissions data across the oil and gas industry. A company can use such comparisons to evaluate its own performance relative to peers, and help identify areas for potential improvement. However, limitations to comparability exist due to various factors including the different methods companies may use to measure, normalize and report their emissions. Although efforts have been made throughout these *Guidelines* to improve comparability, report users are advised to exercise caution when using data from voluntary GHG emissions reports to compare performance. For example, comparing two companies that report emissions on a different basis (e.g. equity share vs. operational control described in Chapter 3) could be misleading regarding actual performance. Specific indicators from similar operations can sometimes be usefully compared to help performance management. However, the company-level, aggregate data typically reported in GHG emissions reports may not provide adequate comparability. Where these *Guidelines* mention comparability, it is not intended to imply that data in GHG emissions reports, and therefore companies' performance, are always directly comparable.

Separate from company GHG emissions reporting, industry associations and others may choose to implement specific performance benchmarking studies, which may build upon the guidance in this document.

It is also recognized that some of the guidance is new, and it may take a number of years for companies to begin to report in accordance with this new guidance. This is particularly relevant for reporting based on the financial control approach described in Chapter 3.

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Acknowledgements

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The *Guidelines* were reviewed by a select group of stakeholders. Their comments and recommendations were carefully considered by the Task Force and were of benefit to the final version of this document. The stakeholder organizations were:

- Defra
- Ernst & Young
- PwC
- WRI

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- Marathon (Chair)
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- IPIECA
- Petrobras
- Repsol YPF
- Shell
- Total

Much of the material contained in these *Guidelines* is based on *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard, Revised Edition* (WRI/WBCSD, 2004)[1], which was used directly or adapted for inclusion in this document. The Task Force wishes to acknowledge the generosity and cooperation of WRI and WBSCD in making the *GHG Protocol* available and allowing material from it to be incorporated into these *Guidelines.*

[1] For the sake of brevity, this document is referred to as the *GHG Protocol* within these *Guidelines.*

1. Introduction

1.1 Background

The petroleum industry has recognized the need for GHG accounting and reporting guidance that is focused specifically on its operations. To help meet this need, member companies of the American Petroleum Institute (API) first published the *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* in April 2001, with a third edition released in August 2009 (referred to as the *Compendium*). The original edition of this publication, *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions* (referred to as the *Guidelines*) was issued in December 2003 to fulfil the need for industry guidance focused specifically on the accounting and reporting of GHG emissions at the facility through to the corporate level. This report is the first revision of the *Guidelines*.

Since the original version of these *Guidelines* was published, GHG emissions reporting has become much more widespread. Regulatory programmes to limit GHG emissions, such as the European Union Emissions Trading Scheme, have led to the mandatory reporting of emissions in some countries. In other countries, such as the USA, mandatory reporting has been implemented at the national, state or regional level in anticipation of expected emission limitations. For companies that are not required to report emissions, or are required to report only for some of their operations, voluntary corporate reporting has also increased.

Recognizing the need to update the original version of the *Guidelines* to reflect changing practices, IPIECA and API jointly initiated the development of this second edition of the *Guidelines* to continue to promote credible, consistent and reliable GHG accounting and reporting practices from oil and gas operations. To maximize the acceptance and use of these *Guidelines*, they have been developed with the broad participation of petroleum operators. To support the goal of wide acceptance, the *Guidelines* have been designed to strike a balance between flexibility and cost-effectiveness in accounting and reporting and the need for consistency and accuracy in the reported results.

The development of these *Guidelines* proceeded in recognition of the large number of existing GHG accounting and reporting approaches. As part of an international effort to bring greater consistency to corporate GHG reporting, the *GHG Protocol* was developed as a multi-stakeholder effort of the World Business Council for Sustainable Development (WBCSD) and the World Resources Institute (WRI) in 2001, with a revised edition published in 2004 (WRI/WBCSD, 2004). The *GHG Protocol* was carefully considered in its original and revised form in drafting the original version of the *Guidelines*, and this edition continues to build upon the *GHG Protocol* as it has evolved. Because the *GHG Protocol* does not focus specifically on the petroleum industry, however, best practices from it have been supplemented and amended with guidance specific to the petroleum industry. These revised *Guidelines* have also aimed to achieve consistency with the approaches described in the IPIECA publication *Oil and Gas Industry Guidance on Voluntary Sustainability Reporting* (IPIECA, 2010; referred to as the *Sustainability Guidance*).

1.2 Purpose

The purpose of these *Guidelines* is to promote consistency in the voluntary accounting and reporting of petroleum industry GHG emissions. While it is hoped that greater consistency will lead to greater comparability in the emissions information reported by petroleum industry companies, these guidelines are not meant to serve as a guide to industry benchmarking. The levels of greenhouse gas emissions that result from industry operations are highly dependent on the nature of those operations—be they the crude oil processed and products produced by an oil refinery or the geology of the reservoirs from which crude oil and gas are obtained. For this reason, the results obtained by applying these *Guidelines* should not be taken as measures of the inherent GHG emissions efficiency of petroleum industry companies.

As the name implies, the purpose of the *Guidelines* is to provide guidance rather than to prescribe standards. Companies vary in how they account for and report GHG emissions. To some extent, this variability may result from the requirements of the mandatory and voluntary reporting programmes in which they participate. These *Guidelines* may be used by companies to understand the implications of the reporting approaches they use and to help them in deciding how to conduct their corporate GHG emissions reporting.

1.3 Scope

Inventorying of GHG emissions by companies is typically conducted as a 'bottom-up' activity by summing emissions from individual sources (or emissions from the total consumption of individual fuel types) at a reporting unit to create an inventory for the reporting unit, and aggregating emissions from the reporting units to create a corporate inventory. Reporting units represent logical groupings of activities and assets for the purpose of reporting GHG data to the parent company, and typically represent the smallest building block of the corporate inventory. These *Guidelines* focus on the accounting of emissions at the level of the reporting unit, and the aggregation and reporting of the results at the corporate level. They do not describe emissions estimation approaches for individual sources, which is the subject of the *Compendium*.

These *Guidelines* have been developed as a complement to the *Compendium* and the IPIECA *Sustainability Guidance.* While the *Compendium* focuses on GHG emissions estimation methodologies for industry sources (how to calculate emissions), the *Guidelines* primarily address GHG accounting and reporting (how to report emissions) for the GHG indicators identified in the *Sustainability Guidance*. Together, these three publications provide a comprehensive set of guidance for the estimation, accounting and reporting of petroleum industry GHG emissions.

When planning the consolidation of GHG data, it is important to distinguish between GHG *accounting* and GHG *reporting.* GHG accounting concerns the recognition and consolidation of GHG emissions from operations in which a parent company holds an interest, and linking the data to specific operations, sites, geographic locations, activities and owners. GHG reporting concerns the presentation of GHG data in formats tailored to the needs of various reporting uses.

Many companies have multiple objectives for GHG reporting, including mandated government reporting, emissions trading schemes and public reporting. In developing a GHG accounting system, a fundamental consideration is therefore to ensure that the system is capable of meeting a range of reporting requirements. Ensuring that data are collected and recorded at a sufficiently disaggregated level, and capable of being consolidated in various forms, will provide companies with maximum flexibility to meet a range of reporting requirements.

As these *Guidelines* should make clear, companies face a range of options when choosing how to account for and report emissions from the facility to the corporate level. Which approach they take will depend on the intended use of the information they are reporting. Reporting emissions from an individual facility as part of a regulatory programme is typically limited to the direct emissions that occur at the site of the facility, and possibly only emissions from sources that exceed a particular size threshold. Emissions are reported for the facility as a whole without regard to how emissions may be allocated among the owners. The rules for reporting these emissions are determined by the specific regulatory requirements. They may or may not correspond either with general industry practice for reporting corporate emissions or with the way the company that owns the facility conducts its corporate accounting and reporting. In considering the broad scope of these *Guidelines*, it is important to bear in mind that, in many cases, the guidance it contains is tailored to specific reporting purposes, and does not necessarily apply for all purposes.

The material in these *Guidelines* is organized into seven chapters:

- Petroleum Industry GHG Accounting and Reporting Principles
- Setting the Boundaries for GHG Emissions Reporting
- Designing an Inventory to Track Emissions Over Time
- Identification of Industry GHG Emissions
- Evaluation of Industry GHG Emissions
- GHG Emissions Reporting
- Inventory Assurance Processes

These chapters are followed by a list of references used in developing the *Guidelines*. A glossary is provided as an appendix.

Chapter 2 describes the overarching principles embodied in the *Guidelines* for accounting and reporting GHG emissions from the petroleum industry. As such, it serves as the basis for the guidance contained in the rest of this report.

Chapter 3 provides guidance on establishing boundaries for the reporting of GHG emissions by companies in the petroleum industry. Since this is an area where companies (and reporting programmes) often differ, the *Guidelines* emphasize approaches to promote consistency. In addition, guidance is provided on accounting for emissions that result from operating relationships common in the petroleum industry, such as production sharing agreements, but which are not typically addressed in general guidance on GHG emissions accounting.

Chapter 4 describes how to design an inventory to track emissions over time. It provides guidance on the various approaches that companies may use to set a base year against which to compare emissions. More importantly, it includes guidance on when and how to adjust the base year approach for changes over time so that performance may be tracked on a comparable basis. It also describes various ways in which petroleum industry companies may demonstrate improvement in their emissions performance.

Chapter 5 provides guidance on the identification of industry GHG emissions, both in terms of the types of gases emitted and the sources of emissions. Chapter 6 covers the quantification and uncertainty of reported emissions. Much of the guidance in these two chapters is of a general nature, as it is not the intent of these *Guidelines* to duplicate the material in the *Compendium* or the publication *Addressing Uncertainty in Oil & Natural Gas Industry Greenhouse Gas Inventories: Technical Considerations and Calculation Methods* (API, CONCAWE, IPIECA, 2009), both of which provide detailed guidance for the petroleum industry. A general discussion of uncertainty in GHG inventories is also included in Chapter 6, based on information from the WRI/WBCSD (2003).

The process for reporting GHG emissions is described in Chapter 7. For corporate reporting, companies may aggregate GHG emissions for various purposes and in various ways including by organizational units, industry subsectors, individual facilities or geographic regions. Guidance is given on consistent approaches to promote comparability across companies, while allowing for the diversity of the different activities within the industry. Part of Chapter 7 is devoted to the question of normalization, providing guidance to better allow comparisons of emissions across companies of different sizes operating in various sub-sectors of the industry.

Chapter 8 focuses on inventory assurance processes. It provides guidance on how companies can use internal resources and programmes, as well as external parties, to provide assurance and to improve their inventory processes. Different types of assurance processes and their uses are discussed.

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2. Petroleum Industry Greenhouse Gas Accounting and Reporting Principles

Companies often adopt or establish sets of principles that serve as the basis for their reporting of environmental information. The principles for GHG accounting and reporting for the petroleum industry listed below are based on those in the *GHG Protocol* (WRI/WBCSD, 2004). The descriptions of the principles that follow build off of the descriptions given in the *Protocol*.

Generally accepted GHG accounting principles, like those for financial accounting, are intended to underpin GHG accounting and reporting to ensure that:

- the reported information represents a faithful, true and fair account of an organization's GHG emissions; and
- the reported information is credible and unbiased in its treatment and presentation of issues.

GHG accounting and reporting practices have continued to evolve and have become more established since the original publication of these *Guidelines*. The principles underlying GHG accounting and reporting, have remained largely unchanged, however. The principles outlined in this chapter are the outcome of a collaborative process involving a wide range of technical, environmental and accounting disciplines.

GHG accounting and reporting should be based on the following principles:

Relevance—Define boundaries that appropriately reflect the GHG emissions of the organizations and the decision-making needs of users.

Completeness—Account for all GHG emission sources and activities within the chosen organizational and operational boundaries. Any specific exclusions should be stated and justified.

Consistency—Use consistent methodologies and measurements to allow meaningful comparison of emissions over time. Transparently document any changes to the data, methods or any other factors in the time series.

Transparency—Address all relevant issues in a factual and coherent manner, based on a clear audit trail. Disclose assumptions and make appropriate references to the calculation methodologies and data sources used.

Accuracy – Ensure that estimates of GHG emissions are systemically neither over nor under actual emission levels, as far as can be judged, and that uncertainties are quantified and reduced as far as practicable. Ensure that sufficient accuracy is achieved to enable users to make decisions with confidence as to the integrity of the reported GHG information.

2.1 Relevance

It is important that an organization's GHG report is relevant. This means that it contains the information that report users—both external and internal to the organization—consider significant and need for their decision-making. Timeliness is a component of relevance, for if information is reported after the time when it can influence decisions, it is no longer relevant.

The selection of reporting boundaries for GHG emissions is an important aspect of relevance. The accounting and reporting boundaries should appropriately reflect the GHG emissions of the organization. The choice of appropriate boundaries depends on the characteristics of the organization, the intended purpose of the GHG information, and the needs of the users. When choosing such boundaries, a number of different factors need to be considered such as:

- Organizational structures—operating licenses, ownership, legal agreements, joint ventures, financial and/or taxation boundaries etc.
- Operational boundaries—direct and indirect emissions from the company's assets and activities.
- The business context—nature of activities, geographic locations, industry sector(s), purposes of information, users of information.
- Specific exclusions or inclusions, which should be transparently identified and the rationale provided.

The boundaries should represent the substance and economic reality of the business, and not merely its legal form.

2.2 Completeness

All emissions within the chosen organizational and operational boundaries that are material to users should be reported to allow the reporting organization's emissions to be assessed. In practice, a lack of data or the cost of gathering data may be a limiting factor in the completeness of the inventory. For cases where emissions have not been estimated, or have been estimated at an insufficient level of quality to be included, the potential impacts and relevancy of the exclusion should be transparently documented and explained.

The principle of completeness should not be confused with, or be regarded as conflicting with, the provision of guidance on *de minimis* reporting levels. Sometimes, a minimum emissions accounting threshold is explicitly defined, stating that a source not exceeding a certain threshold may be omitted from the inventory. Technically, such a threshold is simply a predefined and accepted negative bias in estimates (i.e. an underestimate). Some reporting programmes, however, such as The Climate Registry, do not allow for the exclusion of *de minimis* emissions, but instead allow simplified upper bound estimates for them, while others, such as ISO 14064-1 only allow their exclusion if an explanation is given as to why they are excluded. Under EU and US mandatory reporting programmes, calculation methodologies are provided only for those sources that need to be reported. For other sources, which are not considered to be significant, no calculation methodologies are provided, and thus they do not need to be reported.

In practice, most organizations that report GHG emissions exclude *de minimis* emissions, whether explicitly or implicitly, due to the extremely wide range in the magnitude of GHG emissions from their various activities. So long as the totals of emissions that go unreported are not considered significant by the users of the reported information, this should not be considered to be in violation of the principle of completeness.

2.3 Consistency

Users of GHG information will want to track and compare GHG emissions information over time in order to identify trends and to assess the performance of the reporting organization. The consistent application of boundary definitions, accounting practices and calculation methodologies over time is essential for the production of comparable GHG emissions data. The GHG information for all facilities within an organization's reporting boundary must be compiled in a manner that ensures that the aggregate information is internally consistent and consistent over time. If there are changes in the scope, methods, data or any other factors affecting emission estimates, they should be transparently documented and justified.

2.4 Transparency

Transparency relates to the degree to which information on the processes, procedures, assumptions and limitations of the GHG inventory are disclosed. Information should be reported in a clear, understandable, factual, neutral and coherent manner. Any changes to the data, methods or other factors affecting a time series of reported emissions should be transparently documented. Information on internal audits or external third-party reviews should be included with the report. A 'transparent' report will provide a clear understanding of the issues in the context of the reporting company, and a meaningful assessment of performance.

To promote independent review, the inventory process should be based on clear and complete documentation and archives (i.e. an audit trail). Information should be recorded, compiled and analysed in a way that enables internal reviewers and external verifiers to attest to its credibility. Sufficient information should be provided to ensure that a third party is able to derive the same results if provided with the same source data. An independent external verification is a good way of increasing transparency and determining that an appropriate audit trail has been established and documentation provided.

2.5 Accuracy

Data should be sufficiently accurate and precise to enable intended users to make decisions with confidence. Because the intended uses of inventory data vary, the necessary level of accuracy will also vary. Organizations should ensure that GHG measurements, estimates or calculations are systemically neither over nor under the true emissions value, as far as can be judged, while recognizing the need to balance the cost-effectiveness of obtaining accurate emissions estimates with the intended use for the emissions information. Uncertainties in GHG calculations should be reduced as far as practicable based on the data available to make the calculations[2]. As a means of promoting credibility in their reported emissions, organizations should report on the measures they take to ensure accuracy in their emissions estimation process.

[2] Guidance on assessing uncertainty in GHG emissions inventories has been developed specifically for the oil and gas industry. See *Addressing Uncertainty in Oil & Natural Gas Industry Greenhouse Gas Inventories: Technical Considerations and Calculation Methods* (API, CONCAWE, IPIECA, 2009).

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3. Setting the Boundaries for GHG Emissions Reporting

The petroleum industry encompasses a wide variety of activities, ranging from the discovery and production of oil and gas to the delivery of petroleum products to consumers. Oil companies typically divide these activities into three areas:

- upstream—the exploration, development, and production of oil and gas;
- downstream—the refining, processing, distribution, and marketing of products derived from oil and gas, including service stations operations; and
- chemicals—the manufacture, distribution and marketing of chemical products derived from oil and gas (petrochemicals).

While large, integrated oil and gas companies participate in all of these activities, smaller companies may participate in only one—or part of one—of them. In addition, both large and small petroleum companies may engage in one or more activities that are not typically associated with the petroleum industry, including:

- mining;
- power generation;
- natural gas transmission;
- renewable energy systems; and
- specialty chemical production.

As discussed in Chapter 7, the way in which petroleum companies divide their activities varies from firm to firm. Regardless of how they make these divisions, GHG emissions from all of the activities in which petroleum companies are directly engaged should be included in corporate reporting, provided the emissions fall within the inventory boundaries described in this chapter. Reporting should not be limited to only upstream, downstream and petrochemical activities.

Two types of boundaries are referred to in the context of GHG emissions inventories: *organizational boundaries* and *operational boundaries*. Organizational boundaries refer to those assets which fall within the inventory boundary of a company and the way in which the emissions from those assets are accounted for. Operational boundaries refer to the scope of the emissions that are included in the boundary, in particular emissions that are not from a company's assets, but which may occur as a result of the operation of its assets.

Companies vary in their legal and organizational structures; they include wholly-owned assets, incorporated and non-incorporated joint ventures, subsidiaries and others. In setting organizational boundaries, a company selects an approach for consolidating GHG emissions and then consistently applies the selected approach to define those activities and assets that constitute the company for the purpose of accounting and reporting GHG emissions.

After a company has determined its organizational boundaries, it then sets its operational boundaries. This involves identifying emissions associated with its assets, categorizing them as direct emissions—emissions from assets owned or controlled by the company—or indirect emissions—emissions that are a consequence of the activities of the assets but that occur at companies outside of the organizational boundary. Then, the company chooses the scope of accounting and reporting for its indirect emissions.

Figure 3-1 illustrates the relationship between organizational and operational boundaries. Having defined which assets (or companies) fall under the parent company (the organizational boundary), the company must also define which emissions from those assets—in addition to those it owns or controls—should be included in the inventory (the operational boundary).

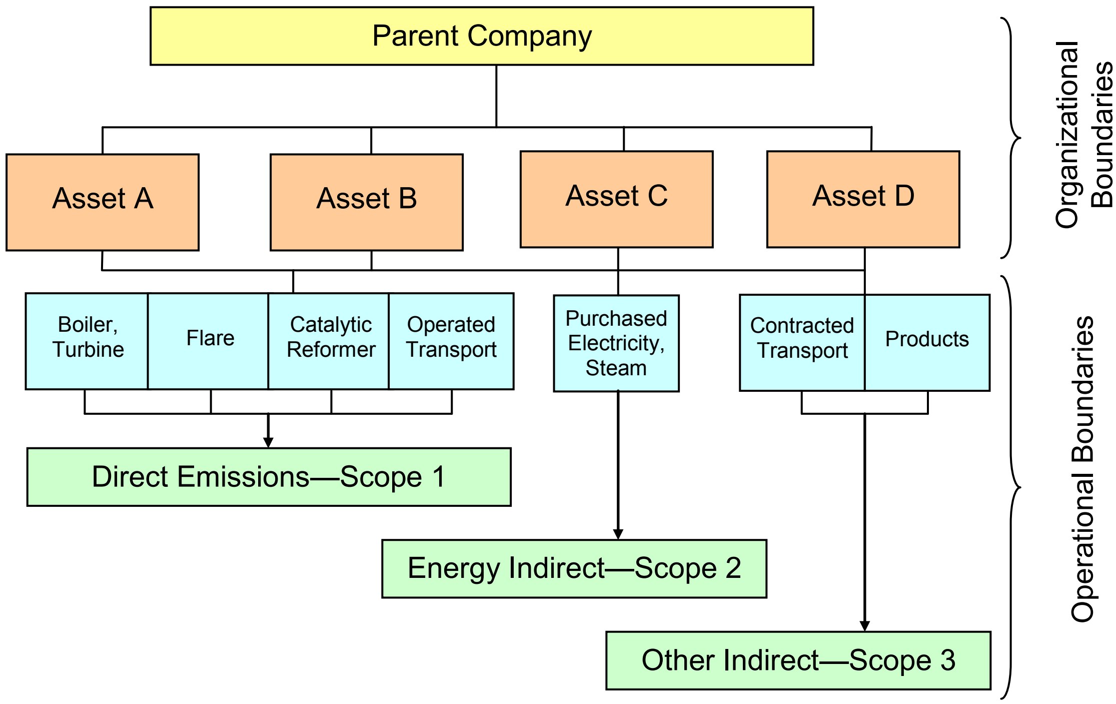


Figure 3-1. Organizational and operational boundaries of a company

The remainder of this chapter describes organizational and operational boundaries as they apply in the petroleum industry. The chapter provides guidance on determining whether GHG emissions fall within the organizational and operational boundaries, and how to account for those emissions if they do. The focus of this chapter is on the accounting of emissions rather than their reporting. Chapter 7 describes how to report emissions across the broad range of activities in which petroleum companies may be involved.

3.1 Establishing Organizational Boundaries

When a company wholly owns and operates an asset, the reporting boundaries for that asset are clear. Emissions from such an asset fall within the company's reporting boundary, and the company should report 100% of the emissions from the asset. When a company owns only part of an asset, owns an asset that is operated by others or operates an asset that it does not own, determining what emissions from that asset fall within its reporting boundaries becomes more complex. These more complex business arrangements often apply in petroleum companies due to the nature of the industry.

Petroleum industry activities are commonly conducted by two or more parties working together in joint ventures[3], instead of by individual firms. These ventures take a variety of legal forms, and may or may not be established as separate legal entities. For the purposes of financial accounting, they are treated according to established rules that depend on the structure of the organization and the relationships among the parties involved. Rules for accounting for GHG emissions from ventures involving more than one party are still evolving, however; the lack of established rules inevitably leads to questions about how the parties participating in these activities should account for and report their emissions.

[3] Unless otherwise indicated, 'joint venture' is used as a generic term in these *Guidelines* for any operations or activities involving more than one party.

The purpose of Section 3.1 is to provide guidance on accounting for GHG emissions from petroleum industry activities that involve more than one party. The guidance builds on Chapter 3 of the *GHG Protocol* (WRI/WBCSD, 2004) on organizational boundaries. It has been tailored to the petroleum industry and simplified to minimize the need to understand financial accounting terminology. The material in Tables 3-1 and 3-2 comes from Chapter 3 of the *GHG Protocol* with some minor modifications.

For corporate reporting, these *Guidelines* should be applied consistently. Existing GHG reporting schemes may have other rules that need to be applied for the entities covered by those schemes. For example, governmental trading schemes are usually based on facility emissions, and do not take into account the ownership structure of the facility. Therefore, the organizational boundary issues discussed in this section would not apply to those schemes. This implies that facilities may have to report different data sets for different reporting purposes. Companies should allow for this flexibility in designing their accounting and reporting systems.

3.1.1 Approaches to Accounting for GHG Emissions: Equity Share and Control

Accounting for GHG emissions from joint ventures may be performed in one of three ways, as illustrated in Figure 3-2 and described below. Reporting may be based on a company's *equity share* of ownership or it may be based on whether the company *controls* the joint venture, in which case it reports all of the joint venture's emissions. *Control* may be defined in either of two ways—*operational control* or *financial control.* These *Guidelines* make no recommendation as to which of these three approaches to use. The equity share and operational control approaches are most commonly used within the petroleum industry for reporting GHG emissions.

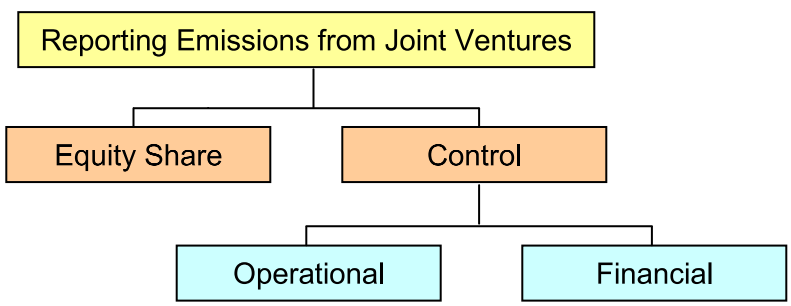


Figure 3-2. Approaches to reporting GHG emissions from joint ventures

Key to applying organizational boundaries on the basis of equity share, operational control or financial control is the concept of the reporting unit. The identification and listing of all of the reporting units that are part of the reporting company for the purpose of GHG emissions reporting should be the starting point for setting organizational boundaries.

Reporting units should be selected to represent the smallest practical building blocks reflecting the internal management of the company and to allow data to be reported at local, country, region or global levels, as appropriate. A reporting unit can be all or part of a subsidiary company, joint venture, investment, facility, plant, office or business location depending on what works best for the company given the way in which it is organized and managed.

Within the oil and gas industry, reporting units are generally grouped by types of upstream and downstream activities, such as exploration, production, drilling, refining, chemical manufacturing and marketing. A company's reporting units manage assets that provide benefits to stakeholders and have intrinsic financial value to the company, but also present associated environmental risks, in particular GHG emissions. Assets may be operated and/or owned by the reporting company. A company will already be organized into groups of activities and assets for financial accounting, and this provides a useful starting point to define the list of reporting units for sustainability reporting.

In the oil and gas industry, ensuring that the company's organizational boundary is correctly described in terms of reporting units can be complex because two or more companies are often commercially involved in an asset, such as in a joint venture, and work together under a variety of legal forms. In order to facilitate consolidation of data by organizational boundary, typically each reporting unit should:

- represent a discrete piece of business that is unlikely to be split during internal restructuring or portfolio change (acquisition or divestments);
- manage assets operated by a single company (i.e. the operator of the reporting unit's assets is either the reporting company itself or another company, so that there is not a mix of different companies operating assets within the reporting unit);
- manages assets which have the same reporting company ownership (i.e. try to avoid creating reporting units that comprise assets with different percentage equity shares); and
- cover a narrow range of related business activities located within one country or region.

3.1.1.1 Equity Share Approach

Under the equity share approach, a company accounts for GHG emissions from reporting units according to its interest in the assets managed by the reporting unit. This reflects economic interest, which is the extent of rights a company has to the risks and benefits flowing from assets. Typically, the share of the risks and benefits in an asset is aligned with the company's percentage ownership of that asset, and equity share will normally be the same as the ownership percentage. Where this is not the case, the economic substance of the relationship the company has with the reporting unit should typically override the legal ownership to ensure that equity share reflects the percentage of economic interest. The principle behind the equity share definition and guidance, that of economic substance taking precedence over legal form, is consistent with international financial reporting. The company should therefore consult with its accounting or legal staff to ensure that the appropriate percentage is applied for each interested operation.

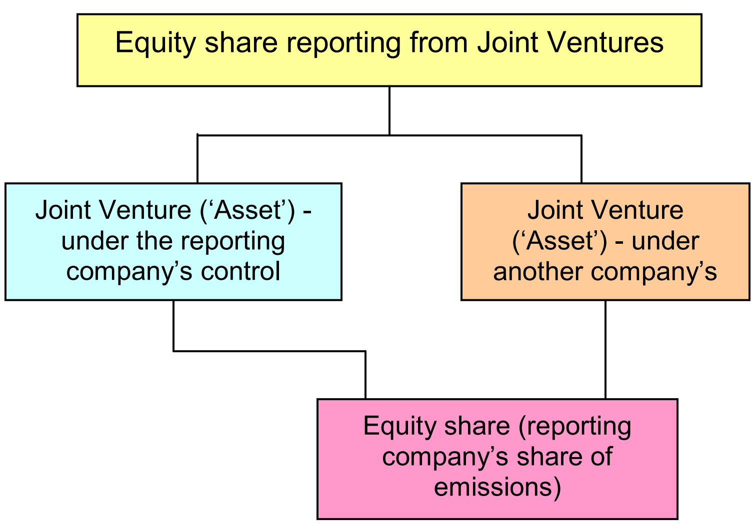


Figure 3-3. Equity share reporting for joint ventures

Figure 3-3 illustrates how equity share reporting works for both controlled and non-controlled joint ventures. Regardless of whose control the joint venture is under, emissions are reported based on the reporting company's equity share.

Typically, in consolidating its GHG emissions, a company will apply its equity share factor at the reporting unit level. If the reporting unit corresponds to the joint venture, this means the total emissions from the joint venture will be multiplied by the company's equity share factor.

3.1.1.2 Control Approaches

Under the control approach, a company accounts for 100% of the GHG emissions from assets over which it has control. It does not account for GHG emissions from assets in which it owns an interest but has no control. Control can be defined in either financial or operational terms. Within the petroleum industry, companies that voluntarily report GHG emissions on the basis of control typically do so using operational rather than financial control.

Companies sometimes report emissions only from joint ventures in which they hold more than a 50% interest. This approach may lead to less complete reporting than is recommended by these *Guidelines* because operational control is not limited to majority-held ventures; it also applies to minority ventures where the company has operational control.

Operational Control

Data are collected from each reporting unit about the assets operated by the reporting company, including those assets partly owned by other companies (i.e. an operated joint venture). Conversely this approach excludes data from assets which are partly owned by the reporting unit but operated by another company (i.e. a non-operated joint venture). The operational control approach is thus generally defined to collect and consolidate all data or information from assets which meet either of the following criteria:

- The asset is operated by the company, whether for itself; or under a contractual obligation to other owners or participants in the asset (for example, in a joint venture or other such commercial arrangement).
- The asset is operated by a joint venture (or equivalent commercial arrangement), in respect of which the company has the ability to determine management and board-level decisions of the joint venture.

When a company (i.e. the parent company and its subsidiaries) reports emissions on an operational control basis, it is done by consolidating 100% of the GHG emissions.

The definition of operational control used in these *Guidelines* is consistent with the 'operational approach' defined in the *Oil & Gas Industry Guidance on Voluntary Sustainability Reporting* (IPIECA, 2010). This particular definition was adopted because it is consistent with the way many petroleum industry companies currently account for and report environmental information. Often, companies report on emissions from assets that they operate (i.e. assets for which they hold the operating licence). It is expected that, except in very rare instances, if a company is the operator of a joint venture asset, it will have the authority to implement its operational policies and thus has operational control.

It should be emphasized that having operational control does not mean that a company necessarily has authority to make all decisions concerning a joint venture. Making decisions on major capital investments without the approval of the other parties in the venture, for example, may be beyond its authority. Operational control does mean that a company has authority to implement its operational policies.

Financial Control

A company has financial control over an asset if the company has the ability to direct the financial and operating policies of the business with a view to gaining economic benefits from its activities (WRI/WBCSD, 2004; DEFRA, 2009). When reporting on a control basis, common practice within the petroleum industry is to use operational control rather than financial control. These *Guidelines* provide an introduction to the application of the financial control boundary in the petroleum industry. It should be recognized, however, that reporting based on financial control is a rapidly evolving approach, and the discussion here represents one point in time. If companies wish to report on the basis of financial control, they may find more information on the approach in the *GHG Protocol* (WRI/WBCSD, 2004) and in the guidance of The Climate Registry (TCR, 2008) and the UK Department for Environment, Food and Rural Affairs (DEFRA, 2009).

3.1.2 Application of the Equity Share and Control Approaches within the Petroleum Industry

Accounting for GHG emissions on the basis of operational control is relatively straightforward in the petroleum industry because it is common practice in the industry for one company to be designated the operator of a joint venture asset. Accounting for GHG emissions based on equity share or financial control results in closer alignment between GHG accounting and financial accounting but is complicated by the wide variety of organizational relationships that are used within the petroleum industry. Some of the more common arrangements within the industry are listed in Table 3-1, along with guidelines on how to account for emissions based on equity share and financial control. For the sake of simplicity, the descriptions of the investments and relationships among the organizations are provided using common industry terminology, rather than accounting terminology. For situations not covered by this table, company financial accountants should be consulted to determine how the specific investment is handled for financial accounting, and the emissions should be accounted for in an analogous manner.

Several of the types of investments listed in Table 3-1 exist in many industries. In general, application of the equity share approach of apportioning GHG emissions according to the economic interest or benefit derived from the venture would utilize the working/participating interest in the venture, or the ownership share if the venture is conducted as a separate company. The application of the financial control approach has similarities to the equity share approach, especially in the treatment of non-incorporated joint ventures, which are common in the petroleum industry. Where the financial control approach differs most critically from the equity share approach for the petroleum industry is in the treatment of emissions from ventures that are conducted as separate companies (e.g. incorporated joint ventures or associates). Such ventures fall outside the financial control boundary, and therefore their emissions would not be accounted for when reporting on the basis of financial control. However, these types of ventures are common in the petroleum industry, and under international financial reporting standards, production from these ventures is typically accounted for on an equity basis in financial statements. If a company wishes to account for its emissions on a financial control basis, it should consider also accounting for the emissions from these ventures as they would likely be considered relevant by stakeholders. If it does so, it should account for them as if it were accounting using the equity share approach, as this is generally consistent with the approach used to account for such ventures in financial statements. Other differences between the financial control and equity share approach are the treatment of Subsidiary companies and Stock ownership in a publicly traded corporation. These differences can be seen clearly in Table 3-1. These general rules would be applied unless there were specific contractual arrangements that either allocate the GHG emissions to the partners (see below), or that alter the normal practice of allocating benefits in proportion to the equity interest and hence contribution of costs.

Table 3-1. Equity share and financial control accounting of GHG emissions for common petroleum industry investments

Type of investment	Description of organizational relationship	Accounting for GHG emissions by equity share	Accounting for GHG emissions by financial control
Subsidiary	The petroleum company either wholly owns the subsidiary, or enough of its voting stock, that it has full control of the subsidiary (e.g. through election of the board of directors).	According to the ownership share of the subsidiary (100% for wholly-owned subsidiaries).	100% of GHG emissions.
Joint venture among two or more oil companies that operates as a separate company.	Several corporations have formed a company by combining some of their existing assets and/or capital. The several corporations are the sole shareholders.	According to the ownership share of each of the parent corporations in the new company.	0% of GHG emissions*.
Joint venture among several oil companies to develop a production asset.	Corporations work in partnership to develop the asset without forming a new company. One serves as operator.	Based on the terms of the arrangement with the other parties—typically according to the working interest.	Based on the terms of the arrangement with the other parties—typically according to the working interest.
Joint venture among a state oil company and several foreign companies to produce oil, as part of a production sharing agreement.	For example, a state oil company has 40% interest in venture, and several companies each have 15% interest or less, including the operator.	Based on company's share of net production.	Not covered specifically by financial control rules.
Stock ownership in a publicly traded corporation—significant share of ownership.	For example, a separate company in which the petroleum company has significant influence[4].	According to the ownership share of the petroleum company in the corporation.	0% of GHG emissions.
Stock ownership in a publicly traded corporation—small share of ownership.	For example, a separate company in which the petroleum company has made an investment, but does not have significant influence[4].	Petroleum company reports no GHG emissions from the company in which it has invested, consistent with financial accounting.	Petroleum company reports no GHG emissions from the company in which it has invested, consistent with financial accounting.

*Under International Financial Reporting Standards, jointly controlled entities may be accounted for using either the proportionate consolidation method or the equity method, although the rule allowing the proportionate consolidation method may change in 2010. Under UK GAAP, unincorporated joint ventures are accounted for using the gross equity method.

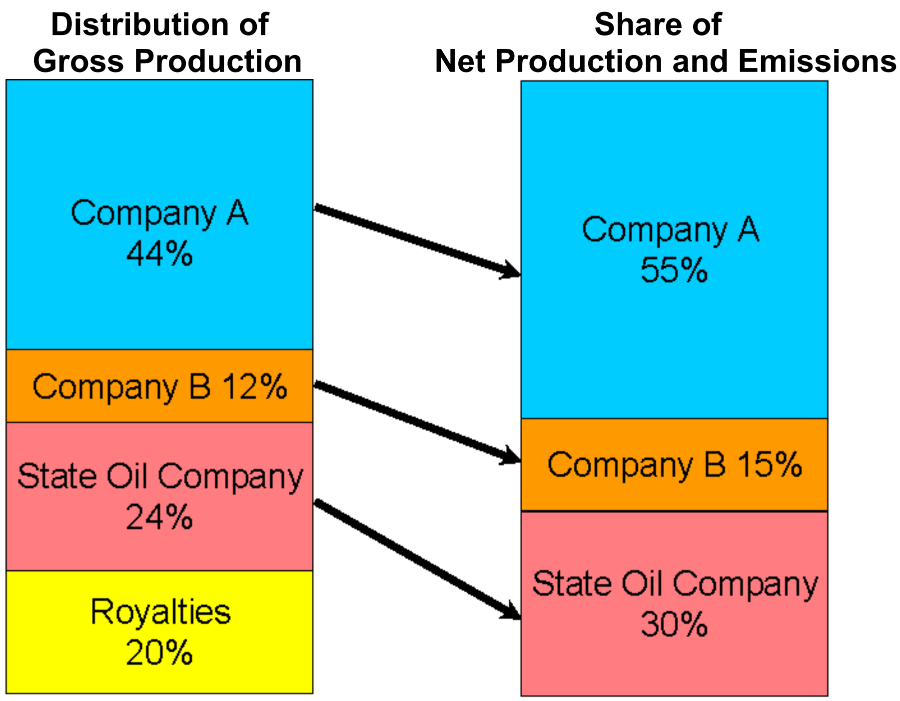
[4] Significant influence is defined by accounting standards; in general, ownership of 20% or more of the stock in a company results in a presumption of significant influence.

One type of arrangement that alters the normal practice of allocating benefits in proportion to equity is the Production Sharing Agreement (PSA), which is commonly used in upstream petroleum activities. A PSA is an agreement between one or more oil companies and a government entity or state company in which the participating oil companies provide financing and bear the risk of exploration and production activities in exchange for a share of the production remaining after royalties[5] are paid to the government. The company share of this remaining production—sometimes referred to as the company share of net production or entitlement production—should be used as the basis for allocating emissions. As shown in Figure 3-4, all of the parties receiving a share of net production, whether they be state-owned or private companies, receive a proportionate share of emissions, and all of the emissions from the asset are accounted for among the companies. No emissions are allocated to the royalties.

The net share of production used for allocating emissions from PSAs is the production reported in financial accounts or statements prepared according to the requirements of UK Generally Accepted Accounting Principles (GAAP), US GAAP, and the US Securities Exchange Commission (SEC). The relevant net production volumes and the company share can be obtained directly from company financial departments.

The types of investments and joint ventures listed in Table 3-1 are simplifications. In some cases, it may be necessary to account for emissions in two or more steps, for example when a parent company has a subsidiary that holds an interest in another company. In these cases, the allocations of emissions should be carried out from the bottom up, so that the GHG data are first consolidated at the lower level organization prior to a higher parent level consolidation. An example is provided in Table 3-2, which illustrates how to account for GHG emissions for a company with a more complicated set of organizational relationships. For each joint venture, the share of emissions that would be accounted for under equity share, financial control, and operational control approaches is listed.

[5] Including taxes and other levies paid in kind (with oil rather than money).



Note: Royalties include taxes and other levies paid in kind (with oil rather than money).

Figure 3-4. Allocation of emissions from PSAs for equity share accounting

Holland Industries is a fictional chemicals group comprising a number of companies and joint ventures active in the production and marketing of petrochemicals. Table 3-2 outlines the organizational structure of Holland Industries and explains how GHG emissions from the different operations are accounted for under the equity share and operational control approaches.

Note that, in this example, Holland America (not Holland Industries) holds a 50% interest in BGB and a 75% interest in Lolo Industrial. GHG emissions are thus apportioned first at the subsidiary level before they are consolidated at the group level.

Table 3-2. Holland Industries—organizational structure and GHG emissions accounting

Name	Legal structure and partners	Interest held by Holland Industries	Operational and EHS policies	Treatment in Holland industries' financial accounts	Emissions accounted for by Holland Industries		
					Equity share	Financial control	Operational control
Holland America	Incorporated company	83%	Holland Industries	Subsidiary	83%	100%	100%
BGB	Jointly controlled, non-incorporated joint venture	50% by Holland America	Partner	Via Holland America	41.5% (83%x50%)	50% (100%x50%)	0%
Lolo Industrial	Subsidiary of Holland America	75% by Holland America	Holland America	Via Holland America	62.25% (83%x75%)	100% (100%x100%)	100%
Kahuna Chemicals	Non-incorporated joint venture, jointly controlled with 2 other partners: ICT and BCSF	33.3%	ICT	Proportionally consolidated joint venture	33.3%	33.3%	0%

Name	**Legal structure and partners**	**Interest held by Holland Industries**	**Operational and EHS policies**	**Treatment in Holland Industries' financial accounts**	**Emissions accounted for by Holland Industries**		
					Equity share	**Financial control**	**Operational control**
Nallo	Incorporated joint venture, other partner Nagua Co.	56%	Nallo	Associated company (Holland Industries does not have financial control since it treats Nallo as an Associated company in its financial accounts)	56%	0%	0%
QuickFix	Incorporated joint venture, other partner Majox	43%	Holland Industries	Subsidiary (Holland Industries has financial control since it treats QuickFix as a subsidiary in its financial accounts)	43%	100%	100%
Syntal	Incorporated company, subsidiary of Erewhon Co.	8%	Erewhon Co.	Fixed asset investment	0%	0%	0%

3.1.2.1 Contractual Arrangements

Companies involved in joint ventures may have contractual arrangements that specifically address the ownership of GHG emissions. When voluntarily reporting emissions, companies should follow the arrangements described in the contracts irrespective of whether they report on an equity share or operational control basis. When reporting under particular regulatory schemes, however, companies should follow the reporting requirements of those schemes.

Production Sharing Agreements typically address the ownership of gas produced in association with oil. In situations where this gas is flared, the accounting of GHG emissions should follow the accounting rules described above without regard to the ownership of the gas. If the PSA explicitly assigns ownership of the GHG emissions, however, this assignment would take precedence over the normal GHG accounting rules. Even if the ownership of the gas and the decision to flare it rests with other parties, and thus the flaring emissions would be accounted for by other parties, a company may wish to report these emissions in a note or explanation to its inventory when the emissions are large.

3.1.3 Selecting Accounting Based on Equity Share or Control

Petroleum companies may choose to report their corporate GHG emissions based on equity share, operational control, financial control, or on multiple bases. Companies should clearly state in their reporting what method they use. When accounting for GHG emissions, they are encouraged to collect sufficient data to employ both the equity share and operational control methods. Companies that operate in areas where financial control is emerging are also encouraged to collect data on that basis. The reason for these recommendations is that a single method has yet to be established among existing voluntary programmes and emerging mandatory programmes that involve reporting of GHG emissions. Accounting for GHG emissions in multiple ways will ensure that companies are prepared for any programmes in which they may choose, or be required, to participate.

Companies that decide to report only on the basis of equity share or control should recognize the benefits and challenges of each, and choose the method that is most suitable for their activities. They should also recognize that whichever method they choose for their corporate reporting, they may be required to utilize other methods for reporting emissions from specific facilities, activities or geographic areas, depending on the reporting requirements of the programmes in which their individual facilities participate.

Reporting based on the operational control approach is appropriate for:

- Companies that choose to voluntarily account for and report their corporate emissions in the same way as programmes that involve GHG accounting based on operational control[6], such as the:
  - EU Emissions Trading Scheme. Emissions limitations under the EU Emissions Trading Scheme are imposed at the installation level. For joint ventures, the operator (the firm that manages or controls the installation) is responsible for ensuring compliance with the scheme and reporting emissions, in much the same way as it would be with other environmental regulations.

  - Mandatory reporting of GHG emissions in the USA required by either the federal government or state governments, which require reporting at the facility level.

[6] The definition of 'control' employed by these programmes may not correspond exactly with that used in these *Guidelines*.

- Performance tracking. Having operational control suggests a greater degree of influence than merely holding a share of the equity.

- Situations where resources for inventorying emissions are limited. Reporting on the basis of operational control can be expected to be less costly than reporting on the basis of equity share because the reporting company will, by definition, have ready access to the data needed to estimate emissions.

Reporting based on the financial control approach is appropriate for:

- Alignment with financial accounting. Similarly to the equity share approach, the financial control approach results in closer alignment between GHG accounting and financial accounting. As discussed in section 3.1.2, it should be noted that the financial control boundary does not include some arrangements that can be common in the petroleum industry and which are equity accounted or proportionally consolidated under international financial reporting standards.

Accounting for GHG emissions based on equity share is appropriate for:

- Liability and risk management. For the purpose of assessing risks posed to a company, GHG emissions accounting and reporting based on equity share provides a more representative and complete picture. Therefore, it provides a realistic picture of liabilities and risks associated with GHG emissions to management, employees, shareholders and other company stakeholders.

- Situations where greater resources are available for conducting the inventory. Reporting on the basis of equity share requires companies to obtain information from other parties for operations they do not control[7]. If this is not possible, they may need to estimate emissions from similar operations for which they have data. In either case, costs may be expected to be greater than for calculating emissions from sources under their operational control.

3.2 Establishing Operational Boundaries

As part of defining the scope of their GHG inventories, companies must determine which emissions related to their activities should be included within the organizational boundaries they have established. This process is referred to as setting the operational boundaries of the GHG inventory.

The guidance in this section builds on Chapter 4 of the *GHG Protocol* on operational boundaries (WRI/WBCSD, 2004) and the section on operational boundaries in the original version of the *Guidelines*. Revisions reflect company experience in implementing the original *Guidelines*.

A key distinction in setting the operational boundaries is whether GHG emissions are categorized as *direct emissions* or *indirect emissions*. Direct GHG emissions are emissions from sources in assets that are managed by a reporting unit, for example: emissions from exhaust stacks in refining and upstream operations; emissions from process vents in oil and gas treatment, oil refining, and chemical production; and exhaust emissions from company-owned motor vehicles and vessels.

[7] To facilitate the reporting of emissions by partners in joint ventures, operators are encouraged to share appropriate emissions data with the other parties.

Indirect GHG emissions are emissions that are a consequence of the activities of the assets managed by a reporting unit, but occur from sources not managed by the reporting unit e.g. emissions from the production of purchased electricity, contract manufacturing, contracted drilling operations and product transport by third parties. These will typically be sources that are neither owned nor controlled by the reporting Company.

Because reporting units represent the smallest building block of the corporate inventory, all of the emissions from sources in assets that are managed by a reporting unit are considered to be direct emissions. For companies that consolidate emissions on the basis of equity share, the equity share fraction is typically applied to the total emissions of the reporting unit to arrive at the equity share direct emissions for the particular reporting unit. For companies that report on the basis of control, the test of whether the company has control is typically applied at the level of the reporting unit, and if it does, 100% of the emissions from the sources managed by the reporting unit are reported as the company's direct emissions from the reporting unit.

Existing guidance on the reporting of corporate GHG emissions typically divides operational boundaries into three 'scopes', and this approach has been adopted for these *Guidelines*. As described below, these three scopes are:

- Scope 1: Direct emissions
- Scope 2: Indirect emissions from energy consumption
- Scope 3: Other indirect emissions

Companies should, at a minimum, account for and report their Scope 1 emissions. They may choose whether or not to report their Scope 2 and Scope 3 emissions. As most voluntary reporting programmes today require that Scope 2 emissions be reported, their separate accounting is recommended as a best practice.

Scope 3 emissions that are included should be identified as such and reported separately from Scope 1 and 2 emissions, as described below and in Chapter 7. In the interest of transparency, companies should clearly state in their inventories which categories of Scope 3 emission sources listed in these *Guidelines* are included.

3.2.1 Scope 1 GHG Emissions

Companies within the petroleum industry should account for and report all Scope 1 (direct) GHG emissions from assets that fall within their established organizational boundaries. The types of Scope 1 emissions sources that occur within the petroleum industry are listed in Chapter 5 and described in detail in the *Compendium*. General categories of Scope 1 emissions sources that should be included in inventories are:

- combustion in stationary sources (e.g. fuel use in engines or turbines used to compress gases, pump liquids and generate electricity, and fuel use in heaters and boilers);
- combustion in flares and incinerators;
- combustion in mobile sources (e.g. transportation in motor vehicles and vessels, such as tank trucks and oil tankers);
- process emissions (e.g. glycol dehydration, acid gas removal/sulphur recovery, hydrogen production, fluid catalytic cracker (FCC) catalyst regeneration);
- venting emissions (e.g. vessel loading, tank storage and flashing, and venting of associated gas);
- fugitive emissions (e.g. leaks from equipment and piping components); and
- non-routine events (e.g. gas releases during planned pipeline and equipment maintenance, releases from unplanned events).

The definition of Scope 1 emissions applies to sources in assets that are managed by the reporting units of the company.

Given the complexity of oil and gas industry operations there is sometimes uncertainty over which physical sources should be considered as being managed by the reporting unit. One area which frequently causes dilemmas is mobile sources, such as vehicles or ships. Such assets are clearly included in the consolidation when owned and operated, but often such assets may be owned by others and leased or chartered by the reporting unit. In such cases, the following guidance may be useful:

- Vehicles, aircraft or rail rolling stock not owned by the company but contractually dedicated for exclusive use by the company are generally included as operated assets for reporting (this excludes spot charters which are available for regular use by other parties).
- There are many forms of contractual mechanisms for marine vessels, but a useful criterion for inclusion as operated assets is that the reporting entity holds the International Safety Management Code Document of Compliance (DOC) (this would typically exclude time-chartered vessels, spot-chartered vessels, or vessels that are owned but not managed by the company where the company would not hold the Document of Compliance).

In addition to mobile sources, the accounting of emissions from leased sources may also cause uncertainty. Because these guidelines recommend that the selected organizational boundary (equity share, operational control or financial control) be applied at the reporting unit level, all of the emissions from sources in assets managed by the company's reporting units are used as the basis for consolidation without regard to whether specific emission sources are owned or leased. The emissions sources in assets managed by the company's reporting units are accounted for as Scope 1 emissions and would be consolidated as part of the total emissions of the reporting unit following the method the company selected for establishing its organizational boundaries.

3.2.2 Scope 2 GHG Emissions

A consistent definition of Scope 2 emissions has emerged among several voluntary reporting programmes. The *GHG Protocol*, The Climate Registry (TCR, 2008), and the UK Department for Environment, Food and Rural Affairs (DEFRA, 2009) all define Scope 2 emissions as energy-related indirect emissions, namely those from purchased electricity, steam, heating (hot water), and cooling. These *Guidelines* adopt the same definition of Scope 2 emissions. This definition does not limit Scope 2 emissions to purchased electricity, as the purchase and sale of both electricity and steam occur commonly among companies within the petroleum industry.

Companies should recognize that GHG reporting programmes differ on their inclusion of Scope 2 emissions. While not required for most regulatory reporting schemes, Scope 2 emissions reporting is recommended by most voluntary corporate reporting protocols. Inclusion of Scope 2 (or Scope 3) is neither inherently incompatible with the conduct of regional or national inventories nor with emissions trading, provided that the programmes are designed properly to eliminate the possibility of double counting.

Consistent with the practice that has evolved in voluntary corporate GHG emissions reporting, these *Guidelines* recommend the inclusion of Scope 2 emissions in the accounting of corporate GHG emissions as a best practice. In the interest of transparency, if companies report Scope 2 emissions, they should report them separately from Scope 1 emissions.

Companies account for and report Scope 2 emissions for a variety of reasons:

- The primary reason for including indirect emissions from energy consumption is to provide a more complete picture of a firm's GHG footprint. In much the same way that reporting on energy consumption, which virtually always includes purchased energy, can be used to assess the risks of rising energy costs, including indirect GHG emissions from purchased energy allows the risks of rising GHG emission costs to be assessed.

- A second reason for encouraging companies to track these emissions is that the information may be needed for some voluntary reporting programmes. The Climate Registry, for example, requires that indirect emissions from the consumption of purchased electricity be reported.

- Another reason for accounting for indirect emissions is that it makes it easier for companies to track changes in emissions that result from outsourcing or insourcing of energy production. Firms that switch from purchasing electricity to generating it on site will be able to more accurately demonstrate the net change in their emissions from the switch if they have been tracking their indirect emissions. If they report only direct emissions, their emissions will appear to increase when they begin to generate their own electricity even if the emissions intensity of their self-generated electricity is less than that of the electricity they formerly purchased. Similarly, if companies switch from generating electricity to purchasing it, they will be less likely to face criticism for exporting emissions if they include indirect emissions from purchased energy in their reporting.

Companies should remain cognizant of the methodological difficulties of determining their Scope 2 emissions. Often, emissions factors for imported energy (e.g. mass of emissions per quantity of electricity consumed) are unavailable or have a high degree of uncertainty. This uncertainty applies to both national emission factors and those published for sub-national areas, including the state-level emission factor published by the US Department of Energy and regional factors published by the US EPA. Since the mix of generation sources supplying an asset vary both over time and within the regions over which the emission factors may have been averaged, indirect emissions calculated with such factors will have much greater uncertainty than estimates of direct combustion emissions. Methods for estimating emissions from purchased energy are described in the *Compendium*.

An additional, though less significant, uncertainty in estimating indirect emissions from the consumption of purchased energy relates to transmission and distribution (T&D) losses[8]. Typically, several percent of the electrical energy generated by power plants connected to the grid is lost before reaching the consumer. Often, emissions associated with T&D losses are not accounted for in corporate GHG inventories, and this approach is recommended in the *GHG Protocol* (WRI/WBCSD, 2004) for companies that only consume electricity and do not transmit or distribute it. Consistent with this practice and due to the fact that most electricity emission factors are based on the electricity generated, rather than the electricity consumed, these *Guidelines* recommend that T&D losses are not included in Scope 2 emissions. If companies choose to report T&D losses, they should report them as Scope 3 emissions.

Indirect emissions result from electricity consumed, both from the grid and from other sources. In many cases, petroleum companies will consume electricity purchased directly from a third party, in which case it is important for companies to understand the source of the energy and whether it comes from a combined heat and power plant (CHP). If it does, the GHG emissions will have to be apportioned between the heat (steam and/or hot water) and power unless the importing facility receives the entire output of the plant.

[8] While T&D losses apply to the transmission and distribution of electricity, losses in thermal energy occur in the transport of steam and hot water from the point of generation to the point of consumption. The discussion in this paragraph would also apply to these losses.

A variety of approaches have been used to allocate emissions between the heat and power streams of CHPs. These methods include the allocation of emissions based on the:

- energy (heat) content of the heat and power streams;
- exergy (work potential) content of the heat and power streams; and
- relative efficiency of heat and power production from separate plants.

Specific guidance on calculating the allocation of emissions between heat and power is given in the *Compendium.* As no allocation method has yet become standard, companies that voluntarily report GHG emissions for their facilities or the corporation as a whole should clearly state in their emissions inventories which allocation method they use.

When reporting under specific GHG programmes, companies should follow the CHP allocation rules established by those programmes. The UK Department for Environment, Food and Rural Affairs (DEFRA, 2009), for example, uses a simplification of the relative efficiency method for allocating emissions between the heat and power streams, while The Climate Registry (TCR, 2008) requires that the allocation be based either on the actual efficiencies of steam and electricity production, or if they are not available, on default efficiencies that are slightly different from the UK values.

For project level reporting of GHG emission reductions, alternative methods of accounting for emissions from CHPs may be more appropriate than the method recommended for facility or corporate reporting. In project-level reporting, emission reductions are typically quantified as the difference between what emissions would have been in the absence of the project and what the actual emissions are with the project. For a CHP project in which power is exported to the grid and heat used internally, this would mean that instead of allocating emissions between the heat and power streams of the CHP, the emissions displaced from the grid could be used in calculating the emission reductions. Information on how to do this may be found in the IPIECA/API report *Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects (*IPIECA, 2007).

3.2.3 Scope 3 GHG Emissions

Scope 3 emissions are all of the indirect emissions that result from a company's activities that are not Scope 2 emissions. They represent emissions that occur in the life-cycle steps of a product or process that occur before the company's activities, such as those resulting from the production and transport of raw materials. They also represent emissions that occur in the life-cycle steps of a product after a company's activities, such as from the transportation and use of products, as well as the disposal of waste materials.

Emissions associated with activities outsourced to other companies are another type of Scope 3 emissions. Within the petroleum industry, a range of emitting activities exist that may be performed by third parties, thus resulting in Scope 3 emissions. In order to make comparisons across companies and industry subsectors, it is important that these sources be accounted for in comparable ways. While these *Guidelines* do not make any specific recommendations for including Scope 3 emissions in voluntary emissions reporting, companies are encouraged to be able to account for selected indirect emissions, as discussed in the sections that follow. In some locations they may me required to report some of the these emissions under mandatory reporting programmes.

3.2.3.1 Emissions Related to Product Use

The principal products of the petroleum industry, hydrocarbon fuels, result in carbon dioxide (CO_2) emissions when consumed. For this reason, GHG emissions from product use are many times greater than the emissions of the petroleum companies themselves.

Consistent with the general practice of reporting Scope 3 emissions, these *Guidelines* make no recommendations regarding the voluntary estimation and reporting of emissions that occur from the use of petroleum products. Emissions that derive from the use of petroleum products are under the control of the product users, and are most appropriately reported by them.

Companies operating in the USA, however, should note that mandatory reporting regulations of the US EPA currently require the calculation of product-use emissions for suppliers of petroleum products (refineries), natural gas and natural gas liquids. Proposed regulations will do the same for suppliers of CO_2.

Trends in product use emissions must be interpreted carefully. If a petroleum company increases its natural gas sales, for example, emissions from product use would appear to increase even if the gas were used to displace coal at a power plant, thereby actually resulting in lower net GHG emissions. Reporting of emissions at the power plant where the fuel switch was made would demonstrate the reductions; reporting by the fuel suppliers would not.

Companies that choose to calculate and report emissions from the use of their products can ensure that appropriate data are used in making the calculations and can provide commentary that explains the data and its limitations. The calculation of emissions from product sales is more complicated than it might appear since oil and gas companies often market fuels produced by other companies and sell their own products for use as feedstock, rather than as fuel. Emissions calculated by others from publicly available product sales data may not make these distinctions, however, and thus may be inaccurate or misleading.

3.2.3.2 Emissions Related to Hydrogen Production by Third Parties

Hydrogen is often used by petroleum refineries in the processing of crude oil, and increasingly it is being used for upgrading crude bitumen and extra-heavy oil to crude oil prior to refining. Refineries may produce their own hydrogen or they may purchase it from third parties located on or near the refinery site. In either case, the hydrogen is typically produced from natural gas or petroleum naphtha, and during the process, $CO_2$is produced. While this carbon dioxide may be captured for other uses, more commonly it is emitted to the atmosphere. Since refineries may consume large quantities of hydrogen, the associated emissions can represent a significant fraction of their direct emissions if they produce the hydrogen themselves, or a large source of indirect emissions if they acquire the hydrogen from other parties.

Since hydrogen produced by third parties is generally considered to be a feedstock rather than an energy source, most companies categorize it as a Scope 3 emission. Due to the magnitude of emissions from hydrogen production, companies that report emissions associated with purchased hydrogen should do so as a separate line item in their Scope 3 emissions. If companies report emissions associated with purchased hydrogen in a different manner, they should transparently document the approach they take.

3.2.3.3 Other Scope 3 Emissions Sources

In addition to Scope 3 emissions from product use and purchased hydrogen production, a variety of other Scope 3 emissions are common in the petroleum industry. These include:

- Third-party shipping of crude oil and petroleum products in vessels, by road transport, by railroad, and by pipeline up to the point of custody transfer (sale to another party).

- Contracted exploration and production activities including well drilling, well maintenance, and well workovers.

- Toll gathering, processing or transport of natural gas and oil for exploration and production (E&P) operations.

- Toll manufacture of chemicals by third parties, which is common in the chemical and petrochemical industries[9]. Companies may choose to include indirect emissions associates from toll manufacture conducted on their behalf as another form of indirect emissions.

In many cases, companies will contract out a portion of the activities listed above, and conduct some of the same activities themselves. They should be able to make rough estimates of emissions from these activities based on the emissions from their own corresponding activities and the extent to which the activities are contracted out versus performed in-house.

Accurately estimating these Scope 3 emission is a challenge for many companies, particularly those that report on an equity share basis. For this reason, and because the other Scope 3 emissions identified above are not expected to be large contributors to the total emissions of most companies, these *Guidelines* do not specifically recommend that they be reported in company emission inventories. However, since such information may be needed to complete industry surveys, it is suggested that companies track such emissions whenever possible.

It should be emphasized that these *Guidelines* recommend that the activities listed above be reported optionally only when they are indirect emissions sources. Transport in company owned and operated vessels, vehicles and pipelines should be reported if they fall within a company's organizational boundaries. Similarly, a company that serves as a toll operator for another firm should include the emissions from the processing it performs. The optional inclusion of emissions from tolling applies only when the tolling operation is performed by a third party on behalf of the reporting company.

If companies do report these forms of indirect emissions, they should report them separately from their direct emissions and their indirect emissions from consumption of purchased energy. They should clearly state in their reporting which of these sources of indirect emissions are included.

A variety of other, minor indirect emission sources are associated with the petroleum industry. While these emission sources may be important for some industries, for larger companies within the petroleum industry, they will be insignificant.

Minor Scope 3 emissions in the petroleum industry include:

- employee travel on third-party vessels, chartered aircraft and commercial airlines;
- transport of employees to remote exploration and production areas, such as offshore production platforms;
- employee commuting to and from work;
- purchased raw materials other than hydrogen and oxygen; and
- waste transport and disposal by third parties.

[9] 'Toll manufacture' or 'tolling' refers to an arrangement whereby one firm provides processing or manufacturing services to another firm, which supplies the raw materials.

Companies within the petroleum industry need to account for these indirect emissions sources only if they have some specific reasons for doing so. Such reasons include the requirements of reporting programmes in which the company participates or if the company (or a particular asset) operates in a narrow sector of the petroleum industry where these emissions may be significant.

4. Designing an Inventory to Track Emissions Over Time

Companies that report GHG emissions generally wish to maintain data consistency over time. They may also wish to track performance over time, either for internal reporting purposes or for demonstrating to external stakeholders their progress in managing emissions. Regardless of the purpose, emissions tracking requires that a reference point exists against which emissions may be compared. In established voluntary reporting programmes, the programme rules may define what this reference point is and how it may need to be adjusted over time. The purpose of this chapter is to provide guidance on maintaining data consistency over time for petroleum industry companies that voluntarily report GHG emissions independently of specific programmes. Much of the material in this chapter, particularly Sections 4.1 and 4.2, come from the *GHG Protocol* (WRI/WBCSD, 2004).

Some companies emphasize total company emissions over time rather than performance with respect to some fixed reference point. In such cases, adjustments are not made to reported emissions over time, but instead historical trends in emissions are reported.

4.1 Establishing Base Year Emissions

A common reference point for tracking company GHG emissions is the actual emissions for a particular year or the average annual emissions over several consecutive years. This emissions level is referred to as the *base year emissions*. The term *base year emissions* is used instead of *baseline emissions* because baseline emissions generally refer to what emissions would have been over time in the absence of specific actions taken to reduce them. (The term baseline is commonly used in the context of emission reduction projects.) The approach of selecting a single base year or average of years for the base year emissions is referred to as a 'fixed base year', as the base year period does not change over time.

Companies may also choose to use a 'rolling base year' approach to tracking their emissions. When using a rolling base year, the base year rolls forward at regular time intervals, usually one year, so that emissions are always compared against the previous year (WRI/WBCSD, 2004). This approach may be desirable when obtaining reliable emissions data for a fixed base year is difficult, such as when a company has frequent acquisitions.

These *Guidelines* make no specific recommendations as to whether a fixed or rolling base year should be used; for those companies that choose to use a fixed base year, the *Guidelines* make no recommendations as to which year or average of years should be chosen to establish the base year emissions. Whichever base year method a company reporting GHG emissions chooses, it is recommended that the method remains unchanged except under certain circumstances.

For companies choosing a fixed base year, it is sometimes suggested that 1990 is used because it is consistent with the base year used in the Kyoto Protocol. (1990 is the year compared to which industrialized countries that have signed the protocol have to reduce emissions between 2008 and 2012). The Kyoto Protocol applies to nations, rather than companies, however, and those nations signing the protocol have not generally required companies to report their 1990 emissions. Companies that have not yet begun (or have only recently begun) to report emissions will usually find it difficult to reliably estimate their emissions as far back as 1990. For other companies, the amount of reorganization that has occurred within the petroleum industry since 1990 makes it difficult to quantify base year emissions that occurred that long ago.

If companies have the option of selecting their base year for tracking emissions, they should:

- ensure that the available data for estimating emissions are verifiable and allow for consistent estimation and accounting across the company; and

- consider the requirements of voluntary programmes in which the company may decide to participate (e.g. choosing a historical year for a base year reporting to The Climate Registry if the company has complete data for that year and all subsequent years).

Whichever base year or average of years a company uses, it should state the reason for making its selection.

Under some reporting schemes, companies may not have the option of selecting a base year. If the required base year is prior to when a company began data collection for emissions reporting, data may not be available for reliable and consistent emissions estimates, and uncertainty may increase. In this situation, companies should make a best effort to obtain reliable data that best reflect past operations.

Companies should recognize that it may not be possible or desirable to have a single base year, or to indefinitely maintain a single base year. While particular reporting programmes may specify a base year, generally these programmes will apply only to certain parts of a large company and not the entire organization. Unless the company wishes to apply the base year for the particular programme to the entire corporation—and has adequate data to do so—it will more likely choose a different base year for the corporation. In addition, as companies grow through acquisitions, the absence of reliable base year data for the acquired firm may require that the acquiring firm choose a new base year that can be applied across the entire organization.

4.2 Adjusting Base Year Emissions

Once a company has selected a base year method for tracking trends in emissions, it is recommended that it makes no adjustments to the base year emissions (or prior year emissions when using a rolling base year) except as described below. Because the approach recommended in these *Guidelines* is to compare emissions against a fixed reference point, or to a previous year, companies should not adjust the base year emissions to account for differences in production from year to year. Rather than adjusting their base year emissions for changes in production, companies should normalize their emissions, as described in Chapter 7, to assess trends in emissions per unit of output.

Organic growth or decline is not considered a condition for base year emissions adjustment. Opening a new facility is considered a case of organic growth because it represents a new source of GHG emissions that did not exist prior to the setting of a base year. Similarly, the acquisition of companies or parts of companies that came into existence after the company's base year was set are regarded as organic growth because these changes represent new GHG emissions that occurred after the base year was set. In the following cases, there should be no adjustments to the base year emissions:

- An operating unit of a company is shut down
- A new operating unit is started
- An acquisition of a company or parts of a company that came into existence after the base year of the acquiring company was set
- 'Outsourcing' of operations that came into existence after the base year was set
- 'Insourcing'[10] of operations that came into existence after the base year was set
- For the outsourcing or insourcing of activities as long as the company is reporting its indirect emissions from the relevant insourced or outsourced activities.

[10] 'Insourcing' refers to the assumption by the company of emitting activities that previously were performed by another company, such as the production of a raw materials, parts and supplies, and heat or electricity.

To track emissions from a consistent set of activities, adjustments to the base year emissions are necessary to ensure that comparisons of annual emissions to the base year emissions are valid. These situations involve the transfer of emission sources that existed at the time the base year was established from one company to another. Unless adjustments to the base year emissions are made, such changes could give the appearance of increases or decreases in emissions, when in fact no changes occurred for the same set of activities; rather, emissions would merely be transferred from one company to another. To prevent this problem, the base year emissions should be adjusted when the following situations occur:

- Significant structural changes to the organization including mergers, acquisitions, and divestitures
- Transfer in the ownership or control of emissions sources
- Outsourcing of emitting activities when the company is not reporting emissions from the relevant outsourced activities
- Insourcing of emitting activities when the company is not reporting emissions from the relevant insourced activities.

In the case of outsourcing and insourcing of emitting activities, there may be cases where adjusting the base year emissions does not affect the total emissions (direct plus indirect) reported by the company. If a company tracks both direct and indirect emissions, and continues to include outsourced activities as indirect emissions in its annual emissions inventory, or if it previously included as indirect emissions outsourced activities that have since been insourced, adjusting the base year emissions will not affect trends in the total reported emissions.

Base year emissions should be adjusted for structural changes when there is significant impact on the reporting consistency of the organization's total emissions. This may include accounting for the cumulative effect of a number of small acquisitions or divestitures. While adding some complexity, this approach aligns with financial accounting practices, and provides a meaningful basis for measuring performance over time.

Base year emissions should also be adjusted for the purchase or sale of significant emissions sources. This might be the case if a company purchased a major asset, for example a power plant or refinery. Similarly, if a company outsources activities that were included in its base year emissions to another company (e.g. transport of its crude oil and refined products), it should adjust its base year emissions to remove these sources if they are significant. Conversely, it should add emissions sources to its base year inventory if it insources activities with significant emissions provided these activities were occurring at the time its base year was established. For both outsourcing and insourcing, however, base year emissions adjustments are unnecessary if reporting the sum of direct and indirect emissions when the emission sources have been included in the base year and will continue to be included in the inventory as either direct or indirect emissions. In this case, the total emissions will be consistent over time provided that both direct and indirect emissions are included in the total.

Companies should also adjust their base year emissions when one or more of the following occur:

- Significant structural changes occur during the year;
- Changes in calculation methodologies result in significant changes in calculated GHG emissions;
- Discovery of errors, or a number of cumulative errors, significantly affecting base year emissions.

The need for making adjustments to base year emissions depends on the significance of the changes, as well as the purpose for restating the emissions. Due to the difficulty and cost of revising data that may be more than a decade old, companies that voluntarily report emissions trends may choose to explain the limitations of their earlier reported data rather than restating the results. If the company is receiving a financial benefit from its reported reductions (such as through emissions trading) or is required to report past emissions under some regulatory scheme, it may not have this reporting flexibility.

These *Guidelines* make no specific recommendations as to what constitutes a 'significant' change and thus the need to adjust base year emissions. Companies should note that some voluntary GHG programmes do specify numerical significance thresholds. For example, The Climate Registry defines significant as a cumulative change of 5% or larger in a reporting entity's total base year emissions (the sum of Scope 1, Scope 2 and Scope 3 emissions—if the company reports Scope 3 emissions—on a CO_2-equivalent basis) (TCR, 2008).

Companies should develop a base year emissions adjustment policy, and clearly articulate the basis for making any adjustments. The policy should state any 'significance threshold' applied for considering base year emissions adjustments. ('Significance threshold' is a qualitative or quantitative criterion used to define a significant structural or other change.) It is the responsibility of the company to determine the significance threshold for considering base year emissions adjustment. In most cases, the significance threshold depends on the use of the information, the characteristics of the company, and the features of structural and other changes.

Once a company has determined how it will adjust its base year emissions, it should apply this policy in a consistent manner. For example, it should adjust for both GHG emissions increases and decreases. The base year emissions should be retrospectively adjusted to allow for specific changes in the company that would otherwise invalidate the use of its base year emissions as a reference point, or would compromise the consistency and relevance of the reported GHG information.

4.2.1 Adjusting Base Year Emissions when Using a Fixed Base Year

The need for adjusting the base year is the same whether a company uses a fixed or rolling base year. The method for adjusting the base year differs however. When adjusting a fixed base year for any of the reasons described in the previous section, the adjustments can be made for the entire year or on a pro-rata basis. It is recommended that the adjustment be made for the entire year of the change, rather than on a pro-rata basis, to avoid having to make another adjustment to the base year in the succeeding year. Similarly, current year emissions should be adjusted for the entire year to be consistent with the base year adjustment. If adjustments were made for only part of the year to compare emissions in year 2015 with emissions in year 2005, for example if a major divestiture were to take place in mid-2015, the base year emissions would have to be adjusted again in 2016 to be able to compare a full year of the change with a like, full base year. By making the adjustment for the full year to begin with, the need for the partial year adjustment of the base year is unnecessary. In either case, the results are the same in years following the acquisition or divestiture as both the base year and the current year emissions would be based on the changes for an entire year.

4.2.2 Adjusting Base Year Emissions when Using a Rolling Base Year

The need to adjust base year emissions is not limited to companies that track their emissions against a fixed base year. Even when a rolling base year is used, adjustments to the base year are needed to make year-to-year comparisons when the significance threshold is met. When using a rolling base year, four different approaches to adjusting the base year may be employed, each with somewhat different results. The differences depend on whether the emission adjustments are made for a full year or on a pro rata basis, and whether they are for the same year as the change or for the following year. Due to the length and complexity of this adjustment process, it is not described here. Companies that use a rolling base year are referred to Chapter 11 of the *GHG Protocol* (WRI/WBCSD) for a general introduction to rolling base year adjustments, and Appendix E of the *GHG Protocol* (WRI/WBCSD, 2005) for a detailed discussion of such adjustments.

4.3 Performance Monitoring

Companies within the petroleum industry demonstrate their GHG emissions performance in a variety of ways. These include:

- demonstrating continuous improvement;
- limiting the absolute level of their emissions;
- limiting the emissions intensity of their operations;
- reporting sustainable operational emissions reductions actually achieved;
- reducing the quantity of gas flared or vented in the production of crude oil;
- improving energy efficiency;
- purchasing renewable or less GHG-intensive electricity; and
- switching to self-generated electricity with a lower emissions intensity than purchased electricity,

These activities are not mutually exclusive, and many companies undertake more than one of them. Each has implications for how the company reports its GHG emissions.

Companies may demonstrate continuous improvement showing that their emissions have decreased from one year to the next by using a rolling base year. Such an approach reduces the need to continually adjust base year emissions since a company need only ensure that emissions for a given year are reported consistently with the previous year.

The demonstration of performance in reducing or limiting the absolute level of emissions relative to a fixed base year requires the establishment and adjustment of base year emissions as described in the in the previous two sections of this chapter. Companies that choose to set an explicit emissions reduction target will need to consider:

- whether to set an absolute or intensity based target;
- which geographic regions will be covered;
- which of the company activities will be included;
- which GHGs to include;
- whether or not to include Scope 2 or Scope 3 emissions;
- what period the target will apply to;
- whether external offsets are part of the target;
- whether to set the target relative to a fixed base year or on a year-to-year basis; and
- what the target will be.

Since detailed descriptions of these considerations for target setting are provided in Chapter 11 of the *GHG Protocol* (WRI/WBCSD, 2004), they are not repeated here. Petroleum industry companies that may be considering establishing intensity-based emission reduction targets should refer to Chapter 7 of these *Guidelines* for information on the types of parameters that may be used for normalizing emissions from various business sectors.

A number of petroleum companies have made commitments to reduce the amount of gas they flare or vent in their upstream operations. Their performance in this regard may be demonstrated by reporting trends in the amount of gas they are flaring and venting. The resulting reduction in CH_4 and CO_2 emissions may also be reported to demonstrate reductions in GHG emissions. Since flaring and venting emissions will typically be part of a company's direct emissions, reductions of flaring and venting emissions will normally be captured in the company's GHG inventory. These reductions may not be readily apparent, however, if the company reports only aggregated emissions results. For this reason, the company may wish to report flaring and venting emissions as a separate category, report the emission reductions directly associated with actions taken to reduce flaring or venting, or report emissions from specific facilities (fields) or activities (upstream operations) to more clearly demonstrate this aspect of its performance.

Whether actions taken to improve energy efficiency are reflected in a company's GHG emissions inventory depends on how the company conducts its inventory and the nature of the energy efficiency improvements. If the efficiency improvements apply to direct emissions sources, such as the company's own boilers, turbines and engines, the efficiency improvements will be reflected in the change in the company's direct GHG emissions. For efficiency improvements that affect indirect emissions, such as improvements that result in the consumption of less purchased electricity, these improvements will only be reflected in the company's GHG inventory if the company reports Scope 2 emissions.

Companies may also reduce GHG emissions by changing the suppliers of electricity to firms that produce renewable or less GHG-intensive electricity. Since emissions associated with electricity consumption are indirect, the emissions benefit of changing suppliers will be reflected only in the inventories of companies that report indirect emissions. The ability to realize these emission reductions also requires having reliable GHG emission factors from the electricity suppliers.

A similar situation—and one that is more common within the petroleum industry—exists for companies that switch from purchasing electricity to generating it on site. If such companies report only their direct GHG emissions, their emissions will increase once they start to generate their own electricity. If their own generation of this electricity is less GHG-intensive than the electricity they formerly purchased, however, the actual net emissions will have decreased. By including indirect emissions in their inventory, companies will be able to demonstrate the emissions benefit of the change. For situations where the company switches to self-generation and exports excess electricity, Chapter 7 describes how to account for net reductions in emissions associated with the exported electricity.

Companies may offset their emissions by investing in external emission reduction projects. Since, by definition, the emission reductions from these projects are external to the company, the reductions would not be captured in the company's own inventory. How external emission reduction projects may be reported is described in Chapter 7. Similarly, companies may acquire emission reductions through trades with outside parties, which may be reported as described in Chapter 7.

5. Identification of Industry GHG Emissions

5.1 Greenhouse Gases

Gases in the atmosphere that allow solar radiation to reach the earth's surface but trap thermal radiation leaving the earth's surface are called greenhouse gases (GHGs). With the exception of water vapor, these gases are present in the atmosphere in trace concentrations. Greenhouse gases enter the atmosphere both as part of natural cycles and as the result of human activities[11].

The most commonly reported greenhouse gases are those covered by the Kyoto Protocol:

- carbon dioxide, CO_2
- methane, CH_4
- nitrous oxide, N_2O
- hydrofluorocarbons, HFCs
- perfluorocarbons, PFCs
- sulphur hexafluoride, SF_6

In addition to this list, some reporting programmes, such as the national inventory reporting programme of the Intergovernmental Panel on Climate Change (IPCC), include emissions of nitrogen oxides, carbon monoxide and non-methane volatile organic compounds when accounting for GHG emissions. These compounds contribute to the formation of tropospheric ozone, which is itself a greenhouse gas.

Emissions of nitrogen oxides (NO_x) should not be confused with emissions of nitrous oxide (N_2O). While NO_x is sometimes used to collectively refer to all compounds containing nitrogen and oxygen, more commonly it is defined as the sum of NO and NO_2. In addition, analytical methods used in the measurement of NO_x emissions do not include N_2O emissions. Therefore, NO_x emissions should not be treated as equivalent to, or including, N_2O emissions when conducting GHG emissions inventories.

Compounds covered by the Montreal Protocol, such as chlorofluorocarbons and hydrochlorofluorocarbons, are also sometimes included in GHG emissions inventories. While these compounds are also GHGs, they currently receive relatively little attention as GHGs because they either have already been, or are being, phased out for most applications.

Other fluorinated compounds, such as nitrogen trifluoride (NF_3) and fluorinated ethers, are potent GHGs but are not controlled under the Montreal Protocol. There has been increasing interest in reporting emissions of these compounds. They are, for example, required to be reported under the mandatory GHG reporting regulations of the US Environmental Protection Agency.

5.1.1 Petroleum Industry Greenhouse Gases

It is recommended that companies within the petroleum industry account for and report all significant emissions of each of the six Kyoto GHGs listed above that fall within their established organizational and operational boundaries. Virtually all companies within the industry would be expected to have emissions of CO_2—and to a lesser extent CH_4, and N_2O—since these gases are emitted during combustion. Both CH_4 and CO_2 are also components of the materials processed by the industry, being that they are produced, in varying quantities, from gas and oil wells. Because the quantities of N_2O produced through combustion are small compared to the amounts of CO_2 produced by combustion and CH_4 produced by venting, CO_2 and CH_4 are the predominant petroleum industry GHGs.

[11] For fluorinated compounds typically listed as GHGs, the atmospheric concentrations are due almost entirely to human activities.

HFCs, PFCs, and SF_6, while not as closely associated with the petroleum industry as other GHGs, may be emitted by various subsectors and operations. HFCs are increasingly used in refrigeration systems, including virtually all motor vehicle air conditioners. Both HFCs and PFCs may be used as solvents, and PFCs are used in some fire extinguishing systems. Sulphur hexafluoride is used in high-voltage electrical equipment, and it is sometimes used as a tracer in pipelines. Since none of these emitting activities are core parts of the petroleum industry, total emissions of these gases would be expected to be small. For particular facilities or activities in which petroleum industry companies have an interest, however, these kinds of emissions may be significant.

The other types of fluorinated compounds, including NF_3 and fluorinated ethers, are not known to be emitted by the petroleum industry. Therefore, they are not generally included in industry GHG emissions inventories.

The discussion above applies to typical petroleum industry operations. Petroleum industry companies whose organizational boundaries include operations such as fertilizer or other chemicals production, semiconductor manufacture, or power generation and transmission—where emissions of trace GHGs may be significant—should consult the relevant industry guidance on how to estimate and report these trace gas emissions. This guidance includes:

- *Sector-Specific Calculation Tools* developed as part of the WBCSD/WRI *Greenhouse Gas Protocol Initiative* related to the manufacture of:
    - nitric acid;
    - ammonia;
    - adipic acid;
    - HCFC-22 (HFC-23 emissions); and
    - semi-conductors.

These tools can be found at www.ghgprotocol.org/calculation-tools.

5.1.2 Greenhouse Gas Global Warming Potentials

The direct effect of GHGs in trapping thermal radiation, their indirect effects in transforming to, or influencing the formation or degradation of, other GHGs, and the lifetime of the gases in the atmosphere vary greatly. In order to account for these differences, the concept of Global Warming Potential (GWP) has been developed. The GWP of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing (warming effect) from the instantaneous release of 1 kg of the GHG relative to that from the release of 1 kg of CO_2. To express emissions on the basis of their global warming potential, the mass of emissions of each GHG is multiplied by its corresponding GWP. The result is referred to as the CO_2-equivalent (CO_2-eq) emissions because the GWPs are based on the warming potential relative to CO_2. Because the GWP of CO_2 is always one, the mass emissions of CO_2 and the CO_2-eq emissions are identical.

Global warming potentials are calculated over different time periods, typically ranging from 20 to 500 years. The most common time period for expressing GWPs is 100 years. The 100-year GWPs for the six GHGs covered by the Kyoto Protocol come from *Climate Change 1995: The Science of Climate Change* (IPCC, 1996), which is commonly referred to as the *Second Assessment Report* (SAR). In 2007, the IPCC published *Climate Change 2007: The Physical Science Basis* (IPCC, 2007), referred to as the *Fourth Assessment Report* (AR4), which contains revised GWPs. The second set of GWP values listed in Table 5-1 come from that report.

Despite being older, GWP values from the *Second Assessment Report* are commonly specified in corporate and facility GHG reporting programmes. Where required, national reporting of emissions on a CO_2-eq basis is currently done using the GWPs contained in the SAR, and is expected to continue to be based on these values until at least 2012. Therefore, for consistency of industry reporting of GHG emissions, it is recommended that companies use the GWPs contained in the SAR and listed in Table 5-1 (the 1996 values). They should continue to use these values until updated GWPs have been accepted by the UNFCCC for national reporting of GHG emissions.

Table 5-1 provides GWPs from both the Second Assessment Report (recommended) and the Fourth Assessment Report (for comparison). Since two of these gases, HFCs and PFCs, represent families of compounds rather than individual chemical species, GWPs are included for selected members of these families.

Table 5-1. Recommended 100-year GHG Global Warming Potentials from the *Second Assessment Report* (SAR) and *Fourth Assessment Report* (AR4)

Greenhouse gas	SAR GWP	AR4 GWP
Carbon dioxide (CO_2)	1	1
Methane (CH_4)	21	25
Nitrous oxide (N_2O)	310	298
HFCs		
HFC-23	11,700	14,800
HFC-32	650	675
HFC-41	97	NA
HFC-125	2,800	3,500
HFC-134	1,000	NA
HFC-134a	1,300	1,430
HFC-143	300	NA
HFC-143a	3,800	4,470
HFC-152a	140	124
HFC-227ea	2,900	3,220
HFC-236fa	6,300	9,810
HFC-4310mee	1,300	1,640
PFCs		
CF_4	6,500	7,390
C_2F_6	9,200	12,200
C_3F_8	7,000	8,830
C_4F_{10}	7,000	8,860
C_5F_{12}	7,500	9,160
C_6F_{14}	7,400	9,300
Sulfur hexafluoride (SF_6)	23,900	22,800

Source: IPCC, 1996; IPCC, 2007
NA=Value not listed in the *Fourth Assessment Report*

As the data in the table illustrate, the newer GWPs vary somewhat from the earlier values—some decreasing, some increasing. Of particular interest to the petroleum industry is the increase in the GWP for methane from 21 to 25. While the use of these values is not recommended at this time, companies should remain cognizant of these values as they are revised, recognize they may need to use them in the future, and understand the implications of the changes on their emission levels.

The recommendation that companies use 100-year GWPs from the SAR is consistent with the most common way of reporting CO_2-eq emissions today. However, scientific estimates of GWPs do change with time, and scientific and policy debate exists over the appropriateness of using the 100-year GWP, or indeed of using some other measure than GWP. Consequently, companies should track their emissions of GHGs on a mass basis, as well as on a CO_2-eq basis, and transparently report which GWPs they use in reporting their emissions.

5.2 Petroleum Industry Greenhouse Gas Emission Sources

Greenhouse gas emissions from the petroleum industry arise from a variety of different types of sources. These sources fall within three main categories:

- combustion emissions—including stationary and mobile combustion sources;
- vented emissions; and
- fugitive emissions.

Stationary combustion emissions include the emissions resulting from the combustion of fuels in boilers, furnaces, burners, heaters, and stationary turbines and engines, as well as the combustion of wastes in incinerators and flares. These sources exist widely within the petroleum industry, and account for most of its GHG emissions.

Mobile combustion sources include combustion of fuels in ships, barges, trains, trucks, automobiles and aircraft. While these sources are also commonly used within the petroleum industry, their emissions are generally much smaller than from stationary combustion sources.

Vented (or process) emissions of GHGs result from the physical or chemical processing of materials—within the petroleum industry, this typically includes gaseous or liquid hydrocarbon streams. Venting of CO_2 removed from gas streams, and the production of CO_2 in the manufacture of hydrogen, are examples of process emissions from the industry. Venting of CH_4 produced with oil, though increasingly rare, is also a process emission. The magnitude of vented emissions varies widely, and may represent significant emissions from some petroleum industry facilities.

Fugitive emissions occur from equipment leaks such as from seals, gaskets and valves. Within the industry, fugitive emissions historically have been of primary concern due to releases of volatile organic compounds (hydrocarbons heavier than methane). In the context of GHG emissions, fugitive sources within the industry are of concern mainly due to the high concentration of CH_4 in many gaseous streams, as well as the presence of CO_2 in some streams. For most types of upstream and downstream operations, fugitive carbon dioxide and methane emissions are insignificant compared to combustion and process emissions. (See the *Compendium.*) For gas pipelines, however, fugitive methane emissions may represent a significant source of GHG emissions.

The source categories listed above are consistent with those listed in the *GHG Protocol* (WRI/WBCSD, 2004). In some guidance, other categories, such as for indirect emissions and non-routine releases may be listed. The actual sources of indirect emissions, as well as non-routine emissions, will generally fall into one of the three categories listed above, however. The division between direct and indirect sources is based on the operational boundaries of the inventory, and the distinction between routine and non-routine releases is an issue of when emissions occur, rather than the type of source they are emitted from. Therefore, neither indirect emissions nor non-routine releases have been identified as separate source categories for the purpose of these *Guidelines*.

For listings of specific GHG emissions sources, the *Compendium* should be consulted. Chapter 2 of the *Compendium* lists specific types of emissions sources, their source category, and the types of GHGs they emit for a large set of petroleum industry sources.

6. Evaluation of Industry GHG Emissions

Quantification of GHG emissions from the petroleum industry is complicated by the wide variety of emission sources and the nature of the fuels consumed by the industry. A large fraction of the industry's combustion emissions comes from burning self-generated hydrocarbon mixtures that are highly variable in composition and are not well characterized by published emission factors. In addition, the quality of information available to calculate emissions, including both the composition and quantities of the materials being combusted may vary substantially among and within industry subsectors.

The level of certainty required for reporting GHG emissions depends on the uses of the data being reported. If the data are being used solely for internal purposes, the needed certainty and completeness of the data may, in some cases, be limited. If the data are to be used for voluntary public reporting, greater certainty will be required. If the emissions data have financial implications for the company, from emissions trading, for example, the certainty of the emissions estimates will be greater still. If data are being reported for regulatory purposes, the level of certainty will be defined by the regulatory programme.

The purpose of this chapter is to provide guidance on levels of uncertainties and completeness associated with petroleum industry GHG emissions inventories. In particular, emissions from major upstream and downstream operations are considered.

This chapter serves as a companion to the *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* (API, 2009) as well as *Addressing Uncertainty in Oil & Natural Gas Industry Greenhouse Gas Inventories: Technical Considerations and Calculation Methods* (API, CONCAWE, IPIECA, 2009, hereafter referred to as the *Uncertainty* document). While the *Compendium* describes methods for estimating industry GHG emissions focusing on individual sources, and the *Uncertainty* document provides technical details on calculating uncertainty, these *Guidelines* provide a general introduction to uncertainty in GHG emissions inventories and qualitative guidance on the relative magnitudes of uncertainty in petroleum industry GHG emission sources.

6.1 Uncertainties Associated with GHG Inventories

The material in Sections 6.1, 6.1.1, and 6.1.2 was taken from *GHG Protocol guidance on uncertainty assessment in GHG inventories and calculating statistical parameter uncertainty* (WRI/WBCSD, 2005) with minor modifications. It is included here to provide a general introduction to uncertainty in GHG inventories. The discussion in this chapter is only focused on the uncertainty in emissions from known sources. It is important to note that there are other sources of uncertainty that can contribute to the overall uncertainty of a corporate emissions inventory. For example, uncertainties may be introduced when dealing with equity emissions (sources operated by third parties) and also in ensuring that all relevant sources are included. In making an overall assessment of uncertainty, companies should remain cognizant of these other issues. At present, there is no recognized guidance on how a company should address uncertainty related to these other issues in an overall assessment of corporate inventory uncertainty.

Uncertainties associated with inventories of GHGs from known sources can be broadly categorized into scientific uncertainty and estimation uncertainty. Scientific uncertainty is a function of the understanding of the science of the actual emission and/or removal process. For example, many of the global warming potential (GWP) values that are used to combine emission estimates of different greenhouse gases involve significant scientific uncertainty (IPCC, 2007). Analysing and quantifying such scientific uncertainty is extremely problematic and is likely to be beyond the scope of most company's inventory efforts.

Estimation uncertainty arises whenever GHG emissions are quantified. Therefore, all emission or removal estimates are associated with estimation uncertainty. Estimation uncertainty can be further classified into two types: model uncertainty and parameter uncertainty[12].

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. For example, model uncertainty may arise either due to inaccuracies in the model itself or to inappropriate parameters (i.e. inputs) used in the model. An example specific to the petroleum industry is flashing emissions of methane, which may occur when crude oil under pressure enters a tank vented to the atmosphere, and may be estimated with a variety of models producing differing results, as described in the *Compendium*. Like scientific uncertainty, estimating model uncertainty is also likely to be beyond the scope of most companies' inventory efforts; however, some companies may wish to utilize their unique scientific and engineering expertise to evaluate the uncertainty in their emission estimation models.

Parameter uncertainty refers to the uncertainty associated with quantifying the parameters used as inputs (e.g. activity data, emission factors or other parameters) to estimation models. Parameter uncertainties can be evaluated through statistical analysis, measurement equipment precision determinations and expert judgment. Quantifying parameter uncertainties, and then estimating source category uncertainties based on these parameter uncertainties, will be the primary focus for those companies which choose to investigate the uncertainty in their emission inventories. In the case of the calculation of emissions from combustion equipment based on fuel flow, uncertainty is associated with the fuel flow parameter, which depends on the proper installation, calibration and accuracy of the metering device.

Figure 6-1 summarizes the different uncertainties that occur in the context of GHG inventories. Guidance on model and parameter uncertainty for petroleum industry GHG emission sources may be found in the *Uncertainty* document.

6.1.1 Limitations and Purposes of Uncertainty Quantification

Given that only parameter uncertainties are within the feasible scope of most companies, uncertainty estimates for corporate GHG inventories will, of necessity, be imperfect. It is also not always the case that complete and robust sample data will be available to assess the statistical uncertainty in every parameter. Often only a single data point will be available for a parameter (e.g. total volume of gas metered over a month). In some of these cases, companies can utilize instrument precision or calibration information to inform their assessment of statistical uncertainty. However, to quantify some of the systematic uncertainties associated with parameters and to supplement statistical uncertainty estimates, companies will usually have to rely on expert judgment[13]. The problem with expert judgment is that it is difficult to obtain in a comparable (i.e. unbiased) and consistent manner across parameters, source categories or companies.

For these reasons, almost all comprehensive estimates of uncertainty of GHG inventories will be not only imperfect but also have a subjective component. In other words, despite the most thorough efforts, estimates of uncertainty for GHG inventories must themselves be considered uncertain. For many types of emissions, uncertainty estimates cannot be interpreted as objective metrics that can be used as an unbiased measure of quality to compare across source categories or different companies. Where emissions consist predominantly of large, well-characterized emission sources, as is often the case for combustion emission sources in the downstream petroleum industry, uncertainty in the estimation of emissions is much less.

[12] Emissions estimated from direct emissions monitoring will generally only involve parameter uncertainty (e.g. equipment measurement error).

[13] The role of expert judgment in the assessment of the parameter can be twofold: firstly, expert judgment can be the source of the data that are necessary to estimate the parameter; secondly, expert judgment can help (in combination with data quality investigations) to identify, explain and quantify both statistical and systematic uncertainties (see following section).

With these limitations in mind, what should the role of uncertainty assessments be in developing GHG inventories? Uncertainty investigations can be part of a broader learning and quality feedback process. They can support a company's efforts to understand the causes of uncertainty and help identify ways of improving inventory quality. For example, collecting the information

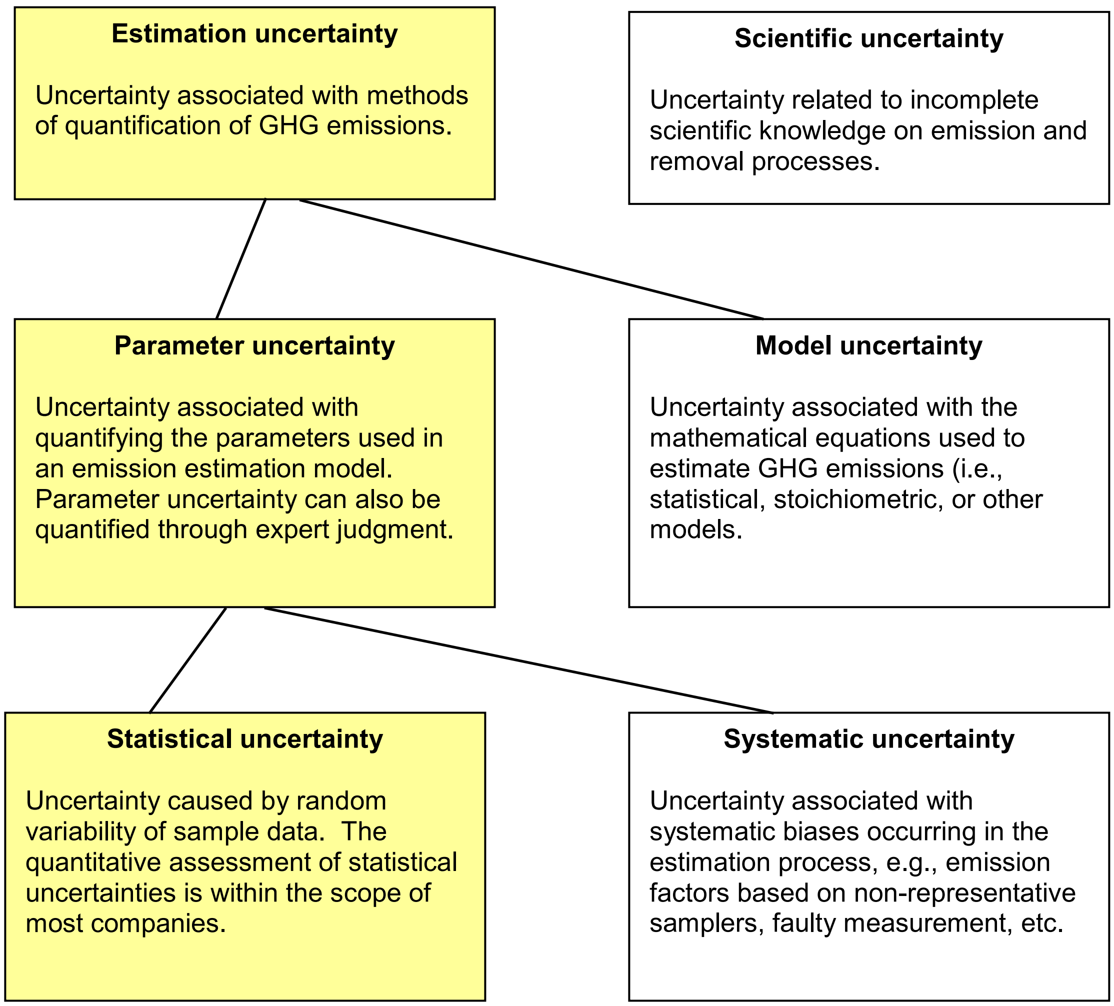


Figure 6-1. Types of uncertainties associated with greenhouse gas inventories

needed to determine the statistical properties of activity data and emission factors forces one to ask hard questions and to carefully and systematically investigate data quality. In addition, these investigations establish lines of communication and feedback with data suppliers to identify specific opportunities to improve the quality of the data and methods used. Similarly, the results of an uncertainty analysis can provide valuable information to reviewers, verifiers and managers for setting priorities for investments into improving data sources and methodologies. In other words, uncertainty assessment becomes a rigorous—although subjective—process for assessing quality and guiding the implementation of quality management. Companies should consider the benefits of doing an uncertainty assessment along with the costs to achieve an appropriate balance of the two.

6.1.2 Parameter Uncertainties: Systematic and Statistical Uncertainties

The types of uncertainties most amenable to assessment by companies preparing their own inventories are those associated with parameters (e.g. activity data, emission factors and other parameters) used as inputs in an emission estimation model. Two types of parameter uncertainties can be identified in this context: systematic and statistical uncertainties.

Systematic uncertainty occurs if data are systematically biased. In other words, the average of the measured or estimated value is always less or greater than the true value. Biases can arise, for example, because emissions factors are constructed from non-representative samples, or because incorrect or incomplete estimation methods or inaccurate measurement equipment have been used[14]. Because the true value is unknown, such systematic biases cannot be detected through repeated experiments and, therefore, cannot be quantified through statistical analysis. However, it is possible to identify biases and, sometimes, quantify them through data quality investigations and expert judgments. If expert judgment is used, it is strongly recommended to use predefined procedures for expert elicitation. A well-designed Quality Management System can significantly reduce systematic uncertainty.

Potential reasons for specific systematic biases in data should always be identified and discussed qualitatively. If possible, the direction (over- or underestimate) of any biases and their relative magnitude should be discussed. This type of qualitative information is essential regardless of whether quantitative uncertainty estimates are prepared, because it provides the reasons why such problems may have occurred and, therefore, what improvements may need to be made to resolve them. Such discussions that address the likely reasons for biases and how they may be eliminated will often be the most valuable product of an uncertainty assessment exercise. Some forms of bias, such as drift in instruments and analysers may be quantifiable using specifications supplied by the manufacturer.

The data (i.e. parameters) used by a company in the preparation of its inventory will also be subject to *statistical* (i.e. random) *uncertainty*. This type of uncertainty results from natural variations (e.g. random human errors in the measurement process and fluctuations in measurement equipment). Random uncertainty can be detected through repeated experiments or sampling of data. Ideally, random uncertainties should be statistically estimated using available empirical data. However, if insufficient sample data are available to develop valid statistics, parameter uncertainties can be developed from expert judgments. For the oil and natural gas industry, the *Uncertainty* document describes the approaches to quantifying each type of these uncertainties and using them to express an overall level of uncertainty for an emissions inventory.

6.2 Relative Uncertainties Associated with Petroleum Industry Emission Sources

Most petroleum industry GHG emissions fall into one of three source categories as noted above, i.e.:

- combustion emissions;
- vented emissions; or
- fugitive emissions.

The sources of uncertainty in emissions vary with each of these categories. In evaluating combustion-related GHG emissions, uncertainties involve the quantity of the fuel being consumed and the composition of that fuel. Fuel composition is particularly important in the petroleum

[14] It should also be recognized that biases do not have to be constant from year to year but instead may exhibit a pattern over time (e.g. may be growing or falling). For example, a company that continues to disinvest in collecting high quality data may create a situation in which the biases in its data get worse each year (e.g. changes in practices or mistakes in data collection get worse over time). Such data quality issues are extremely problematic because of the effect they can have on calculated emission trends.

industry because a large fraction of the fuels are self-generated and have compositions that differ from commodity petroleum products like diesel fuel and natural gas.

Fuel composition is of concern because it determines carbon dioxide emissions, which account for nearly all of the emissions of GHGs in most combustion devices. Emissions of methane and nitrous oxide from combustion sources (other than methane from flares) are very small in comparison and thus of low significance. Methane and nitrous oxide combustion emissions are, however, of high uncertainty. This is clearly a case where investing in uncertainty determinations or reductions is not worthwhile for companies.

For vented emissions from process sources, the models or equations used to calculate emissions of the vented gas and the composition of the vented gas are sources of uncertainty. As noted in the *Uncertainty* document, vented emissions from large process units at refineries and natural gas processing plants are generally better quantified than venting emissions from gas pipeline and exploration and production operations. Uncertainty involving the composition of the vented gas is likely to be greatest for exploration and production operations, since the methane fraction of the gas will vary from field to field and over time. For venting from natural gas pipelines, the composition will be less variable since the gas has been processed into a commodity product.

Fugitive emission rates have large uncertainties associated with them. As with vented emissions, uncertainty surrounding the composition of the gas released depends on the source of the gas. For many types of petroleum operations, particularly refineries and other downstream operations, however, fugitive emissions can be expected to make up a small part of the emissions inventory.

For reporting industry GHG emissions it is important to address the uncertainty associated with individual sources in the context of their contribution to the uncertainty ranges of entire emissions inventories. The discussion in the sections below addresses briefly the importance of different emission sources in terms of the degree of uncertainty associated with them. A more complete discussion of the topic may be found in the *Uncertainty* document. That industry document provides guidance on the applicable statistical methods for calculating source-specific emissions uncertainties and aggregating them, and includes case study examples. A revised version of the *Uncertainty* document, which is expected to contain information on the uncertainties associated with various approaches used to calculate emissions from common industry emission sources is planned for 2011.

6.2.1 Uncertainties in Emissions from Upstream Petroleum Industry Operations

As described above, uncertainty in emissions from petroleum industry sources depends largely on the underlying uncertainties in the quantities of gas combusted or released and the composition of the gas. Figure 6-2 illustrates qualitatively the relative uncertainty associated with various types of upstream petroleum operations. (In this figure it is assumed that for gas turbines and engines, the quantity of gas is not measured.) For quantitative guidance on calculating uncertainty from these sources, the *Uncertainty* document should be consulted.

6.2.2 Uncertainties in Emissions from Downstream Petroleum Industry Operations

In general, the larger emission sources used in downstream petroleum operations will have less uncertainty than those of upstream operations. This is because the quantities of fuels consumed or gases vented are typically closely monitored in refineries. The composition of some of these gas streams, particularly refinery fuel gas, is variable however. Uncertainty in combustion emissions of CO_2 and fugitive emissions of CH_4—as would occur if a fixed combustion emission factor were employed—are minimized through frequent measurement of fuel gas composition. The variability in composition occurs both from differences among refineries and from differences over time within any particular refineries as the product slate shifts over the course of a year, with less short-term variability within any particular refinery. The relative uncertainties associated with major refinery emission sources are illustrated in Figure 6-3.

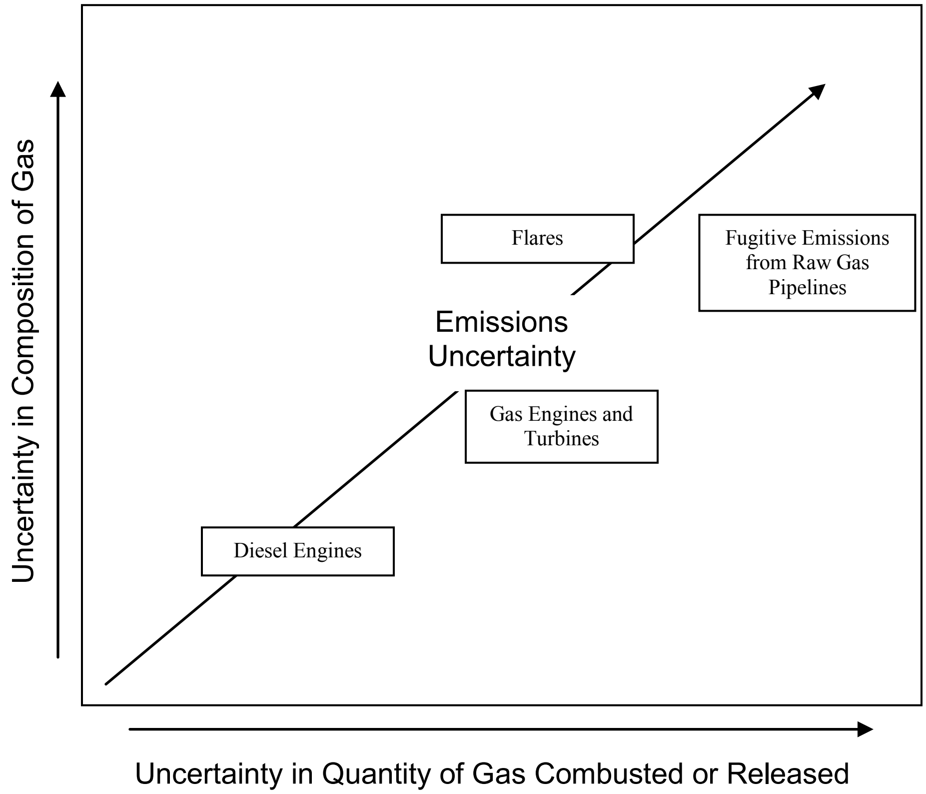


Figure 6-2. Relative uncertainty in upstream GHG emissions

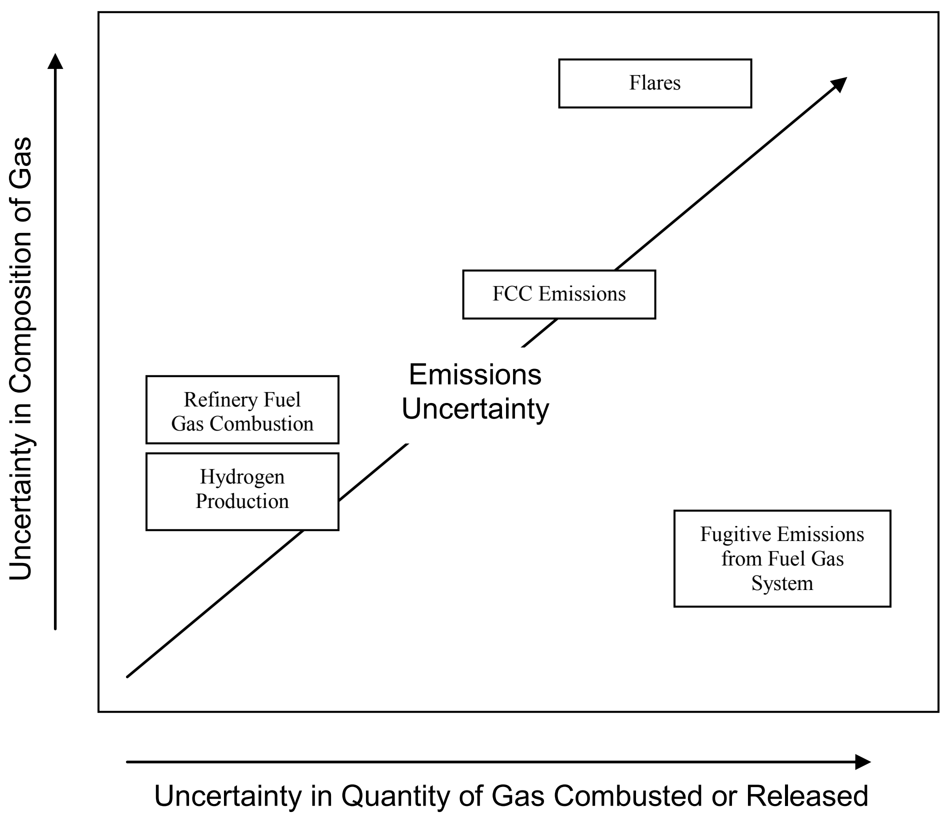


Figure 6-3. Relative uncertainty in downstream GHG emissions

6.3 Assessing Uncertainty in Corporate GHG Emission Inventories

Assessment of the uncertainty in corporate emissions inventories requires that the uncertainty in emissions from the business units, facilities or individual sources that are summed to make up the corporate total are known. For emission uncertainties that are independent of each other, the uncertainty in the sum of the emissions—in absolute terms—can be expressed as:

Equation 1: $T \times t = \sqrt{(A \times a)^2 + (B \times b)^2}$

where :
A = emissions with an uncertainty of +/- a%
B = emissions with an uncertainty of +/- b%
T = A + B = total emissions with an uncertainty of +/- t%

Equation 1 applies regardless of whether A and B are emissions from individual sources or entire facilities. Thus, T could represent the total emissions for a part of a facility, the entire facility, a business unit consisting of two facilities, or an entire corporation. If A and B are individual emission sources, their uncertainty should first be calculated as described in the *Uncertainty* document. If they represent the sum of sources or other subtotals, their uncertainty should be calculated as described in this section.

In the simple case where a corporate inventory consists of just three facilities having emissions A, B, and C, the total emissions and the uncertainty of the total would be:

Equation 2: $T = A + B + C$

Equation 3: $t = \dfrac{\sqrt{(A \times a)^2 + (B \times b)^2 + (C \times c)^2}}{T}$

where :
T = total emissions with an uncertainty of +/- t%
A = facility A emissions with an uncertainty of +/- a%
B = facility B emissions with an uncertainty of +/- b%
C = facility C emissions with an uncertainty of +/- c%

In applying Equation 3, the calculation of the uncertainty in the total emissions does not depend upon how the inventory is aggregated below the corporate level. Mathematically, the results are the same, whether the corporation first sums individual sources at the facility level and then at the business unit level before summing to arrive at the corporate total, or whether it sums individual sources to arrive directly at the corporate total. As long as the uncertainties in the sources are independent, the methodology for calculating the total uncertainty first at the subtotal level and then for the total is the same as calculating the total uncertainty directly from individual sources. If the uncertainties in the emissions being summed are not independent (i.e. if they are correlated in some way) the methodologies described in the *Uncertainty* document should be used for assessing the uncertainty of the total.

Equations 1 and 3 can be used to illustrate the important influence of large sources on the total uncertainty of corporate GHG inventories. In the case of two facilities, one with emissions of 100 +/- 5.0% and the other with emissions of 10 +/- 20%, the total emissions and uncertainty are 110 +/- 4.9%. Even though the uncertainty of the smaller facility is four times that of the larger one, the uncertainty in the total is nearly equal that of the larger one (but smaller than for either facility).

6.4 Reducing Uncertainties in Petroleum Industry Emission Inventories

Corporate GHG emissions inventories within the petroleum industry are typically made up of many different emission sources of widely varying sizes. As illustrated in the previous section, to reduce uncertainty in the corporate inventory, it is important to focus on the largest emission sources. This statement applies to both the type of operations that result in emissions and the specific GHG being considered.

The GHG emissions considered in this chapter are limited to CO_2 and CH_4 because they are the principal GHGs emitted by the petroleum industry. Emissions of nitrous oxide (N_2O) are not considered to be major sources of uncertainty in industry emissions inventories. While N_2O emissions are highly uncertain, and N_2O is formed in all combustion processes, stack test analyses indicate that the amounts produced are negligible when compared to emissions of CO_2—even when accounting for the high GWP of N_2O. Since N_2O emissions are not known to occur from other types of petroleum industry sources—fugitive or process emissions—they cannot be significant contributors to emissions uncertainty at the corporate level.

For combustion emissions of self-generated fuel, uncertainty can be reduced through measurement of fuel gas composition. Where the composition of gas streams is periodically sampled, increasing the frequency of sampling will reduce the overall uncertainty of emissions estimates, particularly for large gas streams of variable composition and flow. Gas streams that have relatively constant compositions will require less frequent sampling; those with more variable compositions will require more frequent sampling. In addition, it is important that the locations for sampling gas composition produce results that are representative of the composition of gas actually being burned.

If measured gas composition data are not available, emission calculations should be made using mass-based emission factors (mass of CO_2/mass of fuel) and the actual mass of fuel burned, or be made using energy-based emission factors (mass of CO_2/energy content of the fuel) and the actual amount of energy consumed. Using volume-based emission factors that have not been derived specifically for the composition of the fuel of interest will produce much greater uncertainty in the calculated emissions.

Measurement of the quantity of fuels combusted will also reduce uncertainty of calculated emissions. Typically, fuel consumption of the largest equipment sources is measured, while smaller pieces of equipment or flares are less likely to be. Cross-checking may also be used to reduce uncertainty. For example, where liquid fuels are distributed from a single large tank to smaller tanks, consumption based on volume changes of the larger tank may be compared to the sum of changes in the smaller tanks. To minimize uncertainty, efforts should focus on the largest sources of unmeasured consumption.

Direct measurement of emissions such as through the use of continuous emissions monitoring systems (CEMS) also involves measurement uncertainty. In addition to the uncertainty associated with measuring the concentration of CO_2 or other GHG in the flue gas, the volumetric flow rate of the flue gas itself must be measured. For the petroleum industry, the uncertainty in these measurements, especially the flue gas flow rate, means that the uncertainty associated with CEMS may be equal to or greater than that based on measured fuel volumes, as measured fuel volumes are typically more accurate than measured flue gas flow rates.

For vented and fugitive emissions, uncertainty depends on how well both the quantities of gas released and the composition (methane fraction) of the gas are known. For many types of industry operations, the volumes of gas vented are much greater than fugitive releases. Therefore, overall uncertainty will be improved more by reducing the uncertainty in these quantities than by seeking to improve fugitive gas emissions estimates. The need for measuring the composition of the vented or fugitive gas to reduce uncertainty will depend on the nature of the gas and how variable its composition is over time. Model uncertainty related to the quantity of vented and fugitive emissions can be significant and difficult to address.

6.5 *De Minimis* Emissions

Companies conducting emission inventories inevitably make decisions concerning sources and GHGs that they include in their inventories, or that they deem to be insignificant and therefore exclude. Such decisions may be based on the estimated percentage of the total emissions that may be contributed by a source, or may be based on a fixed numerical threshold. Government programmes for reporting or regulating emissions often take the latter approach, for example, excluding facilities with emissions of less than 25,000 tonnes of CO_2-eq from their requirements. Thresholds of this type are typically based on emission sources across a wide representation of industry and are meant to serve a particular policy objective of the regulatory programme, rather than as a *de minimis* level of reporting for a particular company.

Voluntary corporate reporting guidance varies in its approach to the inclusion of *de minimis* emission sources. The *GHG Protocol* does not recognize the practice of excluding emission sources that fall below a particular size threshold in order to promote the goal of inventory completeness. The Climate Registry guidance also does not allow for the exclusion of *de minimis* sources. It does, however, allow for the use of simplified emission estimation methodologies for small sources that may account up to 5% of a reporter's GHG inventory.

ISO guidance on GHG reporting (ISO 14064-1) states that 'the organization may exclude from quantification direct or indirect GHG sources or sinks whose contribution to GHG emissions or removals is not material or whose quantification would not be technically feasible or cost effective.' The organization must provide an explanation of why certain GHG sources or sinks are excluded from quantification. Companies participating in voluntary reporting programmes or following specific guidance will want to review their internal policies to ensure that they meet the programme requirements.

Whichever approach a company takes to *de minimis* emissions will have the effect of introducing a bias into its reported emissions. If sources below a particular threshold are omitted, the inventory will have a pre-established negative bias. If instead, all sources are included, but simplified emissions estimation methods are used, the inventory will likely have a positive bias. This is so because simplified methods tend to be conservative—that is, they produce results that tend to be greater than the actual emissions. Conservative estimation methods are used in order to be sure emissions are either not being under-reported or that more precise emission calculation approaches are not needed, as would be the case for larger emission sources.

These *Guidelines* make no specific recommendation concerning a *de minimis* level of emissions that can be left out of a GHG inventory. A specific *de minimis* level of emissions is not recommended because a level that is insignificant for one facility, such as an oil refinery, may be highly significant for another, such as a terminal. Where companies do wish to apply some form of test on their emission levels, it is recommended that they apply it collectively to all sources within a facility or subsector. This will ensure that the total of many small sources does not become a significant omission. Companies that apply a numerical threshold for their reporting should document that information with their inventory.

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7. GHG Emissions Reporting

When reporting emissions as part of an established GHG programme, companies should follow the rules of those programmes. For the voluntary public reporting of GHG emissions, it is recommended that companies within the petroleum industry follow the guidance provided in this chapter. The guidance below and in parts of Sections 7.1 and 7.2 come from the *GHG Protocol* (WRI/WBCSD, 2004). Sections 7.1 and 7.2 also draw upon data aggregation and normalization approaches employed by IPIECA.

Content of a Public GHG Emissions Report

A public GHG emissions report should include the following kinds of information:

1. Description of the company and inventory boundary:
   - An outline of the organizational boundaries chosen, including the chosen consolidation approach.
   - An outline of the operational boundaries chosen, and if Scope 3 is included, a list specifying which types of activities are covered.
   - The reporting period covered.

2. Information on emissions:
   - Emissions data separately for each scope chosen to be reported.
   - Emissions data for all six GHGs separately (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6) in metric tonnes or in tonnes of CO_2 equivalent with the GWPs used to calculated the equivalent emissions stated.
   - Information on which regulatory programmes, such as those of the European Union, Canada, Australia, the USA or others, serve as the basis for any of the emissions data, and how these emissions are handled to arrive at the total emissions.
   - Approach for establishing a base year, including, if appropriate, an emissions profile over time that is consistent with the chosen policy for making base year emissions recalculations.
   - Appropriate context for any significant emissions changes that trigger base year emissions recalculation (acquisitions/divestitures, outsourcing/insourcing, changes in reporting boundaries or calculation methodologies, etc.).
   - Emissions data for direct CO_2 emissions from biologically sequestered carbon (e.g. CO_2 from burning biomass/biofuels), reported separately from the scopes.
   - Methodologies used to calculate or measure emissions, providing a reference or link to these methodologies or any calculation tools used.
   - Any specific exclusions of sources, facilities and/or operations.

3. Optional information

Information on emissions and performance

As background for its public GHG emissions report, a company should internally maintain the following additional information, some of which it may choose to include in its report, or make available upon request:

- Emissions data from relevant Scope 3 emissions activities for which reliable data can be obtained.
- Emissions data further subdivided, where this aids transparency, by organizational units/facilities, country, source types (stationary combustion, process, fugitive, etc.) and

activity types (production of electricity, transportation, generation of purchased electricity that is sold to end users, etc.) provided this information is not considered confidential.

- Emissions attributable to self-generated electricity, heat or steam that is sold or transferred to another organization (see Chapter 3).
- Emissions attributable to the generation of electricity, heat or steam that is purchased for re-sale to non-end users (see Chapter 3).
- A description of performance measured against internal and external benchmarks.
- Emissions from GHGs not covered by the Kyoto Protocol (e.g. CFCs, NO_x,), reported separately from scopes.
- Relevant ratio performance indicators (e.g. emissions per kilowatt-hour generated, tonnes of material production, or sales).
- An outline of any GHG management/reduction programmes or strategies.
- An outline of any external assurance provided and a copy of any verification statement, if applicable, for the reported emissions data.
- Information on the causes of emissions changes that did not trigger a base year emissions recalculation (e.g. process changes, efficiency improvements, plant closures).
- GHG emissions data for all years between the base year and the reporting year (including details of, and reasons for, recalculations, if appropriate).
- Information on the quality of the inventory (e.g. information on the causes and magnitude of uncertainties in emission estimates) and an outline of policies in place to assure inventory quality. (See Chapter 8).
- Information on any GHG sequestration.
- A list of facilities included in the inventory.
- A contact person.

Information on offsets:

- Information on offsets that have been purchased or developed outside the inventory boundary, subdivided by GHG storage/removals and emissions reduction projects specifying whether the offsets are verified/certified and/or approved by an external GHG programme (e.g. the Clean Development Mechanism, Joint Implementation).
- Information on reductions at sources inside the inventory boundary that have been sold/transferred as offsets to a third party, specifying whether the reduction has been verified/certified and/or approved by an external GHG programme.

The intent of reporting information in this way is to provide the recipient of the information with sufficient context to interpret it. Companies will need to exercise judgment in determining how to report the listed information and how much to report. For example, the principal GHGs emitted by the petroleum industry are CO_2 and CH_4, and thus most companies will not need to report all six GHGs listed above. Similarly, the reporting of normalized emissions is useful only if the activity causing the emissions is well-defined and readily quantified (see Section 7.2). Similarly, the types of supporting information suggested for reporting will not be appropriate for all companies, and it may not be possible to include a large amount of detail in published company environmental or sustainability reports. If this is the case, companies should make the more detailed information available by other means, for example, through their website or their inventory contact person.

7.1 Data Aggregation

Greenhouse gas emissions may be aggregated across a range of dimensions including organizational and operational boundaries, geographic boundaries, industrial sectors, company divisions, facilities and source types. As discussed in Chapter 3, companies typically set their overall organizational boundaries for reporting either on the basis of equity share, operational control or financial control. Those companies that can report on more than one basis are encouraged to do so.

7.1.1 Aggregating by Operational Boundaries

For their selected organizational boundaries, petroleum industry companies should report their operating emissions in three separate categories:

- direct emissions (Scope 1);
- indirect emissions from energy imports (if reporting such emissions) (Scope 2); and
- other indirect emissions specified by subcategory (if reporting such emissions) (Scope 3).

The reason for reporting different types of emissions separately is to provide a clear picture of which GHG emissions are being reported. Emissions reporting should also be complete within each category or sub-category. Direct emissions should include any emissions associated with the production of exported energy such as steam or electricity. If a company chooses to report indirect emissions from the consumption of purchased energy, then the reported amount should be completely separate from the direct and other indirect emissions categories and should represent a complete inventory of the indirect emissions from energy imports. If a company chooses to report other indirect emissions, then they should be reported completely separately from direct emissions and indirect emissions from consumption of purchased energy. Each subcategory of other indirect emissions included in the inventory should be listed, and reporting should be complete within each sub-category. This means that if a company chooses to report a particular type of indirect emissions, it should report those emissions for all of its relevant sources, and not report them selectively.

Companies that export energy may choose to report the emissions associated with the exported energy in a note or memo accompanying their reported emissions or as part of the supporting information that accompanies their data. In addition, if they have installed a generating facility (or cogeneration facility) that results in a net reduction in GHG emissions, they may quantify those reductions as a specific emission reduction project and list them as emission offsets in their inventory. It should be noted that there is uncertainty associated with the magnitude of such reductions due to difficulty determining what type of energy production is offset by exports. To enhance the credibility of the reported reductions, the company should note whether the emission reductions have been verified according to an established offset methodology.

Figure 7-1 illustrates how corporations would report their GHG emissions for different operational boundaries. In this example, *direct* emissions of 80 (including 15 related to exported energy) are reported separately from indirect emissions. Indirect emissions consist of emissions from consumption of purchased energy (30) and other indirect emissions (10), the indirect emissions from imported energy being reported separately from other listed indirect emissions. In addition to its direct and indirect emission sources, however, this corporation has implemented projects that result in emission reductions outside of its reporting boundary (20). The projects might be the installation of cogeneration facilities that export electricity, thereby displacing emissions from the generation of more CO_2-intensive electricity.

It is common practice today for companies within the petroleum industry to be exporters of energy (electricity, steam or hot water). Some companies have set up subsidiaries or joint ventures for the purpose of generating electricity for sale. Refining and petrochemical operations often cogenerate steam and electricity, selling the electricity they do not need for their own production processes. When reporting their GHG emissions, companies should include emissions from exported energy in their total direct emissions, as shown in Figure 7-1. Any net reductions that result from displacing more highly emitting energy sources outside of the company's reporting boundary should be reported separately as project-based emission reductions, but not subtracted from the company's total emissions.

Companies may choose to separately track emissions from exported energy and report this information either in a note accompanying their emissions inventory or in the supplemental information they provide. Tracking emissions from exported energy will allow them to consistently aggregate and normalize their emissions as described in Section 7.2.

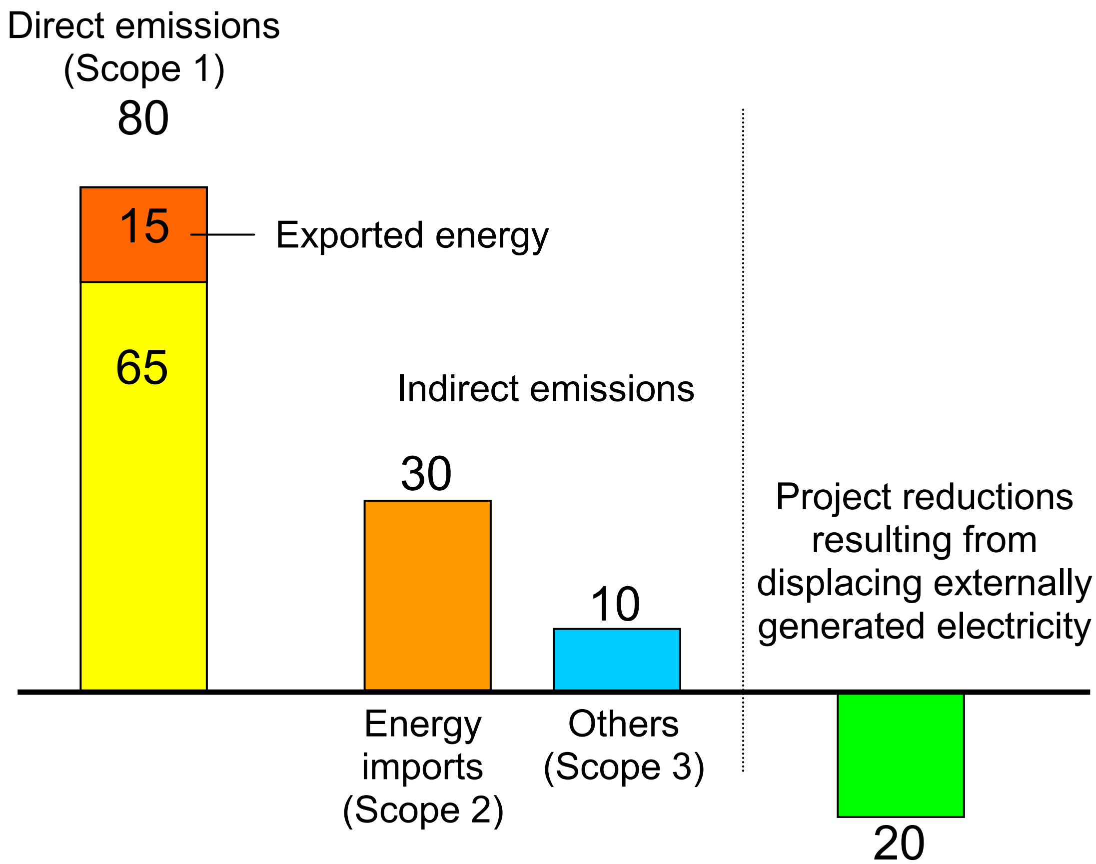

Figure 7-1. Emissions aggregation along operational boundaries

The estimation of emissions associated with the energy exported from combined heat and power plants is handled in a manner analogous to that for estimating emissions from energy imported from such plants. Companies will need to apportion the GHG emissions associated with a plant's exported energy between heat and power in the same manner as they do for imported energy, unless they export all of the heat and power from the plant. Since most refineries and petrochemical plants with cogeneration facilities typically use at least some of the produced energy internally, it is expected that apportionment of emissions will be necessary in most cases. Approaches to allocating cogeneration emissions are described in the API *Compendium*.

7.1.2 Aggregating Along other Dimensions

Companies report on their GHG emissions at varying levels of aggregation ranging from individual sources to the entire corporation. Reporting at the source level is done, for example, by companies in the USA. that are required to report CO_2 emissions from electric generating units regulated under the US EPA Acid Rain Program. Reporting at the corporate level is most commonly done as part of the internal reporting of emissions data and as part of voluntary public reporting.

Data aggregation at one or more levels between individual sources and the entire corporation is commonly required for programmes that involve GHG reporting. Programme rules define how data should be aggregated. The EU Emissions Trading Scheme, for example, requires the reporting of emissions at the installation level, and reporting in the USA, Australia, and Alberta, Canada is required at the facility level. Because rules for aggregation vary, companies should maintain their emissions data in as disaggregated form as possible. This will allow them to easily aggregate the data according to the rules of whichever scheme in which they may choose to participate.

For voluntary reporting outside of established GHG programmes, companies may wish to aggregate and report emissions (by scope) at multiple levels, including:

- for specific, major facilities;
- by geography, e.g. country, province, or state; and
- by organizational unit.

These *Guidelines* make no specific recommendations about which of these levels of aggregation companies should report. If, however, companies aggregate and report other environmental data at these levels, it is recommended that they do the same for GHG emissions.

Companies within the petroleum industry vary widely in the breadth of their operations. Some have only exploration and production operations; others are primarily refiners or petrochemical producers. The largest companies operate across all of the major subsectors. For this reason, companies may wish to report their emissions of GHGs by industry subsector. At present, however, there are no widely accepted definitions of just what the industry subsectors are or how, exactly, they should be defined. While the terms ‘exploration and production’, ‘refining” and ‘chemicals’ are commonly used and widely understood as general categories within the industry, the activities these subsectors vary from company to company. For example, transportation of crude oil between production operations and refineries may be included as part of production operations or as a separate subsector. Similarly, transportation of refined products may be included in a refining subsector, as part of marketing or as a separate subsector. Also, company businesses that are used as the basis for reporting may not correspond to industry subsectors, which further complicates the process of reporting by subsector.

The IPIECA *Sustainability Guidance* notes that relevant environmental performance data in the petroleum industry is dependent on the type of operational activities within various sub-sectors of the industry. It recommends tracking data, including emissions, by the following industry subsectors:

- exploration and production;
- refining;
- transportation and terminals;
- pipeline;
- marketing (retail);
- marine; and
- petrochemicals.

The aggregation of emissions by industry subsector is done to better enable comparisons to be made among participating companies and to facilitate the normalization of emissions as discussed in the following section of this chapter. Companies that are not currently reporting subsector emissions along other dimensions and have not already determined how they should aggregate their emissions are encouraged to follow these subsector divisions.

Some companies may need to expand the categories listed above. This table does not contain separate subsectors for gas processing or liquefied natural gas (LNG) production. Companies with such facilities may wish to report emissions from them as separate categories.

This list also does not contain a specific industry subsector for merchant power production or on-site cogeneration facilities. Some organizations favour the reporting of electricity generation as a separate subsector in order to more clearly demonstrate the emission reductions associated with cogeneration and to eliminate one variable in benchmarking emissions from refineries.

When reporting information for industry subsectors, it is important that companies explicitly state which type of emissions are being reported: direct emissions, direct plus indirect emissions, or direct emissions plus indirect emissions from energy imports minus emissions from energy exports. The use of the latter approach should be viewed as an emerging best practice as it eliminates one source of variability when benchmarking emissions from facilities or sectors.

7.2 Normalization of Emissions Data

There are two principal aspects of GHG performance that are of interest to management and stakeholders: the absolute quantity of GHG emissions and the quantity of emissions relative to some measure of output. The measure of output may be in physical units, such as tonnes, barrels, or kilowatt-hours, or it may be in terms of the monetary value of the output, e.g. emissions per dollar of sales. Emissions expressed in terms of output or input are referred to as 'normalized' (or sometimes as 'rate-based') emissions.

Care should be taken in interpreting and reporting normalized emissions. Output measures represent gross indicators of production and do not take into account the varying nature of specific operations. Emissions from oil production, for example, will vary greatly depending on the need for enhanced oil recovery techniques such as steam injection and whether the associated gas produced with the oil is flared or captured for sales. Similarly, refining emissions will depend on the type of crude oil processed and the mix of products produced, with more highly refined products resulting in greater emissions. Therefore, the normalized emissions should be presented as gross measures for comparison of similar operations of individual companies or for similar operations across companies, rather than as measures of inherent emissions efficiency.

If emissions are normalized, it is essential that the organizational boundaries for the emissions and the output measure are the same. Thus, if emissions are calculated based on equity share, the basis for the normalization of these emissions must be measured using the same equity share boundary.

The normalization of emissions facilitates comparisons between similar products and processes, while accounting for differences in production levels. Companies report normalized emissions for a number of reasons including:

- tracking performance over time;
- comparing performance among similar operations within the company; and
- facilitating comparisons with other companies.

Corporations should normalize their emissions in ways that make sense for their activities and support their decision-making. Within the petroleum industry, the emissions profile of facilities within particular subsectors, such as oil refining or production, may vary greatly even when the operations produce similar products. For the purpose of internal improvement processes, it may be appropriate to account for the differences in these processes when normalizing emissions. For external, public reporting, a gross normalization based on output may be more appropriate. Corporations should normalize emissions for external reporting in a way that permits a better understanding and interpretation of their performance for their stakeholders than merely reporting absolute emissions. It is important for companies reporting normalized emissions results to provide perspective on issues such as the scope and limitations of the normalization in order to give greater context to the users of the information. In particular, they should indicate the scopes of the emissions being normalized, for example whether they are Scope 1 (direct emissions) only or Scope 1 plus Scope 2 (direct plus indirect emissions from energy consumption).

As noted above, emissions may be normalized on the basis of the physical quantities or on the basis of the value of the output. Because the values of petroleum industry outputs are closely tied to the price of crude oil, it is recommended that companies do not normalize emissions in monetary terms. The wide variability in the prices of crude oil from year to year—and within the course of a year—would cause emissions normalized on the basis of monetary output to have little meaning. In addition, for companies that report emissions on an operational control basis, the normalized emissions would also have little meaning because the denominator—economic output—is not typically measured on the same basis. Therefore, it is recommended that emissions be normalized on the basis of physical units.

At present, the bases for normalizing emission within the petroleum industry have not yet been firmly established. Given the wide range of activities within the industry, and the fact that many petroleum industry companies conduct only a limited set of these activities, a single basis for normalization is not possible. It is, however, possible to normalize emissions for specific subsectors. In fact, many companies currently normalize their emissions of GHGs and regulated air pollutants in their public reporting of emissions (e.g. see IPIECA, 2010).

IPIECA's *Sustainability Guidance* recommends normalization factors corresponding to the various petroleum industry subsectors. These factors are listed in Table 7-1. For companies that have not already established normalization factors, it is recommended that these factors be used for their voluntary reporting. Because the IPIECA factors do not specify which units are to be used for these factors, companies reporting normalized emissions should be careful to state which units they use.

Table 7-1. IPIECA normalization factors for environmental reporting

Oil and gas industry activity	Normalization factor
Exploration and Production (upstream)	Wellhead production of crude oil, condensates, natural gas liquids and dry gas (including flared gas and gas used for fuel but excluding gas reinjected into the reservoir) on operated basis *Note: equity share GHG emissions may be normalized using net export production on an equity share basis, as in financial reporting*
Refining	Refining throughput of crude oil and other feedstock
Transportation and Terminals	Product delivered or terminal throughput
Pipeline	Pipeline throughput
Marketing (retail)	Motor fuel sales
Marine	Cargo volume transported
Petrochemicals	Petrochemicals production

Source: IPIECA, 2010

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8. Inventory Assurance Processes

Companies within the petroleum industry report GHG emissions for a variety of reasons. Depending on the purposes of reporting, stakeholders will have varying expectations concerning the quality of the reported data. The different reporting purposes and expectations for the reported data indicate the need for a range of assurance processes for petroleum industry GHG emissions inventories. Chapter 6 described the quality of reported emissions data in the context of emissions uncertainty. This chapter discusses in broader terms the elements of a quality system to provide assurance on inventory results as well as the process for verifying emissions inventories.

In general, the level of assurance required for GHG emissions data will increase as a company moves from internal reporting to public reporting, to reporting for a regulatory or financial purpose. For data that are being used only within the firm, internal assurance processes may be sufficient. For data that are being reported publicly, companies may wish to engage external assurance providers. For data reported to established emissions trading schemes and some voluntary reporting programmes, external assurance will typically be required.

The material that follows in this chapter is based on two chapters of the *GHG Protocol* (WRI/WBCSD, 2004)—one on managing inventory quality, the other on verification of GHG emissions. Those chapters were combined, shortened and edited for inclusion here.

8.1 Inventory Management Systems

Companies can facilitate the assurance of their GHG inventories through the use of effective management systems. In many cases, companies within the petroleum industry will already have such systems in place for collecting and reporting other forms of environmental data. Extending the systems to GHG emissions data should be straightforward. Companies that do not have such systems in place should consider the benefits of adopting them. Having a management system in place will reduce the resources required to provide assurance on their inventory, regardless of whether the assurance is conducted internally or externally.

A practical framework is needed to help companies design their inventory programme and quality management system, and to help them develop a plan for its progression into the future. Such a framework should address the institutional, managerial and especially the technical attributes of inventory preparation. This simple framework has four fundamentals:

- Methods
- Data
- Inventory processes and systems
- Documentation.

Each of these four fundamentals is described below.

Methods: Methods are the technical aspects of inventory preparation. Companies should select or develop methodologies for estimating emissions that accurately represent the characteristics of their source categories. These *Guidelines* and the *Compendium* describe many calculation methods to help companies with this effort. The design of a company's inventory programme and quality management system should address the ongoing needs, not just for the selection, but also for the application and updating of inventory methodologies as new research becomes available, as changes are made to operations, or as the importance of inventory reporting is elevated due to emerging or evolving regulatory and voluntary reporting programmes. Companies should seek to ensure the quality of these components at every level of their inventory design.

Data: This is the basic information on activity levels, emission factors, processes and operations. Although methodologies need to be appropriately rigorous and detailed, data quality is more important. No methodology can compensate for poor quality input data. The design of a corporate inventory programme should facilitate the collection of high quality inventory data and the maintenance and improvement of collection procedures.

Inventory processes and systems: These are the institutional, managerial and technical procedures for preparing GHG inventories. They include the team and processes charged with the goal of producing a high quality inventory. To streamline GHG inventory quality management, these processes and systems may be integrated, where appropriate, with other corporate processes related to quality.

Documentation: This is the record of methods, data, processes, systems, assumptions and estimates used to prepare an inventory. It includes everything employees need to prepare and assure a company's inventory. High quality, transparent documentation is particularly important to credibility.

A quality management system is important to ensure that an inventory continues to meet the principles of these *Guidelines* into the future. However, it is recognized that companies do not have unlimited resources, and so the quality of the inventory, the extent of quality management activities, and whether uncertainty assessments are made will be a function of these resource limitations. Additionally, unlike financial accounting, corporate GHG inventories are a scientific and engineering exercise without legally sanctioned accounting standards. Given these facts, companies will have to approach the design of their own inventory programme and quality management system as a cumulative effort over multiple years, in keeping with the broader evolution of policy and their own corporate vision.

Companies are not expected to rigorously implement every component of a quality management system in the first few years that they begin preparing an inventory. However, they should begin incorporating quality management procedures in the design of their inventory programme from the beginning. The rigor and coverage of certain procedures may be phased in over several years. For example, initial efforts may focus on direct emissions, the largest source categories, categories with the most dramatic trends, mitigation efforts or cases where significant changes are occurring in business processes. In general, the initial focus of quality management should be on collecting high quality data and building systems for its collection.

Companies should consider the integration of their inventory quality management system with their overall corporate and environmental information management systems, such as ISO 9000 (Quality Management) or ISO 14001 (Environmental Management) certifications. In addition, they should consider ISO 14064-3 (Greenhouse Gases—Specification with guidance for the validation and verification of greenhouse gas assertions) for guidance on the verification/validation process.

8.1.1 Implementation of Inventory Quality Management Systems

Although principles and broad programme design guidelines are important, any guidance on quality management would be incomplete without a set of practical measures that can be implemented on actual data and calculations. A company should be able to implement these measures at multiple corporate levels, from the point of primary data collection to the final corporate approval process. Implementation of these measures is most important where data are initially collected and where calculations and data aggregations are performed. Initially, it may be the final inventory totals at the corporate level that are viewed as the most useful. However, companies may wish to consider ensuring the quality of their data at various levels of disaggregation (e.g. facility, process, operations within a state or province, according to a particular scope, etc.) so that they are better prepared for possible markets or regulatory rules in the future.

While implementing their quality management measures, companies should also focus on ensuring the quality of information related to their emission trends, not only on the quality of a single year's inventory estimates. A practical approach to achieving this principle of time series consistency is to focus the company's effort on minimizing biases in the methods and data used for their base year and current year estimates.

The third component of a quality management system is generic quality checking procedures. These procedures should be applied, as appropriate, to all source categories and all levels of inventory preparation. An example list of detailed measures is given in Table 8-1.

Table 8-1. Generic quality management measures

Data gathering, input and handling activities

- Check a sample of input data for transcription errors.
- Identify inventory process modifications that could provide additional controls or checks on quality.
- Ensure that adequate version control procedures for any written procedures or electronic files have been implemented.

Data documentation

- Confirm that bibliographical data references are included in spreadsheets or other calculation tools for all primary data.
- Check that copies of cited references have been archived.
- Check that assumptions and criteria for selection of methods, activity data, emission factors, and other parameters are documented.
- Check that changes in data or methodology are documented.

Calculating emissions and checking calculations

- Check whether emission units, parameters, and conversion factors are appropriately labeled.
- Check that units are properly labeled and correctly carried through from beginning to end of calculations.
- Check that conversion factors are correct.
- Check the data processing steps (e.g. equations) in any calculation tools that are used.
- Check that input data and calculated data are clearly differentiated.
- Check a representative sample of calculations.
- Check some calculations with abbreviated calculations (i.e. back of the envelope checks).
- Check the aggregation of data across source categories, organizational units, etc.
- When methods or data have changed, check consistency of time series inputs and calculations.

The fourth component of a quality management system is source category-specific quality checks and investigations. The following discussion addresses the types of source-specific quality measures that can be employed for emission factors, activity data and emission estimates.

Emission factors
For a particular source category, calculated emissions will generally rely on emission factors. For mandatory reporting of emissions, the emission factors may be specified by the reporting programme, and these factors should be used for sources within that programme. For voluntary

reporting of emissions, published or default emission factors, or fuel, device or site-specific emission factors may be employed for sources outside of regulatory-mandated programmes. Entities should not keep ‘two sets of books’ due to differing emission factors. When voluntarily reporting emissions from sources that are covered by regulatory mandated programmes, the emission values should be the same as those actually reported through the mandatory programme, rather than the values that would have been reported if the sources were not part of the regulatory programme.

Quality investigations should assess the representativeness, applicability and reasonableness of emission factors when used for voluntary reporting. Even where companies are required by regulation to use specific emission factors, they may wish to do the same investigations as a check on the regulatory factors. The characteristics of the company’s operations should be compared to the conditions of the studies in which emission factors were derived. Within the petroleum industry, company and site-specific emission factors for CO_2 will often be more reliable than default (or regulatory) factors due to the variable nature of fuels combusted in the industry. Files containing the documentation of any such investigations should be maintained to allow for future retrieval of the information should it be requested by verifiers or other interested parties.

Activity data
Possibly the most important input to a company’s inventory is the activity data it collects. Therefore, establishing robust data collection procedures should be a priority in the design of any company’s inventory programme. Several useful measures for ensuring the quality of activity data are given below:

- Data should be collected from metered or measured sources, if possible, either from purchase records or from company measurements.
- Current year data should be compared with previous year’s data and historical trends. If data do not exhibit relatively consistent changes from year to year, but rather undergo sharp increases or decreases, then the causes for this pattern should be investigated and explained.
- Activity data from multiple reference sources (e.g. government survey data or data compiled by trade associations) should be compared with corporate data when possible. Although all data may have the same origin, such checks can at least ensure that consistent data are being reported to all parties.
- Activity data will usually be generated for purposes other than preparing a corporate GHG emissions inventory. Thus, companies should check the applicability of their data to inventory purposes, including checking for completeness, consistency with the source category definition, and consistency with the emission factors used. For example, data from different operating sites should be examined for inconsistent measurement techniques, operating conditions or technologies. In addition, quality control measures (e.g. ISO) may have already been conducted during the data’s original preparation. It should be determined whether these measures are adequate compared to the company’s inventory quality management plan.
- Companies should investigate whether any biases or other characteristics that could affect the quality of their data have already been identified (e.g. by communicating with experts in the company or elsewhere).
- If companies are using additional data to estimate emission intensities or other ratios, quality management measures should also extend to these additional data.

Emission estimates
Estimated emissions for a source category in a given year can be compared with historical data or other estimates to ensure that they fall within a range that is reasonable (changes of more than 10% from year to year may warrant further investigation). Potentially unreasonable estimates provide cause for checking emission factors or activity data, and determining whether changes in methodology, market forces or other events are sufficient reasons for the change. In situations

where actual emissions monitoring occurs (e.g. power plant CO_2 emissions), then the data from monitors can be compared with estimated emissions using other activity data and emission factors.

If any of the above emission factor, activity data, or emission estimate checks indicate a problem, more detailed investigations into the accuracy of the data or appropriateness of the methods may be required.

8.2 Verification

The previous section describes internal processes and measures that companies may adopt to ensure the reporting of high quality GHG emissions data. As a check on these measures, companies may wish to verify their emissions data. Depending on the purpose of their GHG reporting, they may be required to have their emissions verified.

Verification is an objective assessment of how complete and accurate a GHG inventory is, as well as how well it conforms to pre-established GHG accounting and reporting principles. Verification involves evaluating and testing the supporting evidence (in the form of an audit trail) of the GHG inventory compilation. The practice of verifying corporate GHG inventories is still evolving, and the absence of universally accepted GHG accounting and reporting standards for voluntary reporting means that reporting standards against which verifications take place may vary from company to company. For mandatory reporting programmes (typically for specific installations), reporting standards are specified by the programme, and verification standards are much more uniform.

Emissions verification may be conducted by independent third parties or internally, through a process of self-verification. Many companies are interested in improving their GHG accounting and reporting systems and often conduct their own internal verification. If a company decides to initiate an internal verification it is preferable, for reasons of objectivity, that this activity be undertaken by a group independent of those responsible for preparing the GHG inventory and report.

This section provides background on the verification process and identifies the key aspects that companies should be aware of when compiling a GHG inventory and establishing internal reporting and documentation systems. Even if a company is not intending to conduct verification at this time it should still develop its inventory in a manner that is amenable to verification in the future, as discussed in Section 8.1.

One of the most important considerations, in terms of verification, is to ensure transparency and auditability of inventory data. Verification of a transparent and well documented system is easier, and ultimately cheaper, than one that is not well documented. The overall goal of the verification process is to determine whether the GHG report being verified is a faithful and accurate reflection of the reporting entity's position. As outlined in Chapter 2, there are a number of key principles that should be adhered to when compiling a GHG inventory. Adherence to these principles is the basis of successful data verification.

8.2.1 Objectives

Before commissioning and planning verification, the reporting company should clearly define its objectives and decide whether an external verification is the best way to enhance them. Reasons for undertaking verification include to:

- meet the requirements of emissions trading or other greenhouse policies and programmes;

- improve internal GHG accounting and reporting practices (data calculation, recording and internal reporting systems, application of GHG accounting principles, (e.g. checks for completeness, consistency, accuracy, etc.), and to facilitate learning and knowledge transfer within the organization;
- increase management and board confidence in reported information; and
- add credibility to publicly reported information and reduction goals, and to enhance stakeholder trust in the reporting organization.

Firms deciding to have their inventories verified will need to assess whether they need an independent third party to conduct the effort, and if it is to be done internally which type of staff will conduct it. Whether the verification is conducted by an independent third party, or as an internal activity, verifiers should follow similar procedures and processes.

8.2.2 The Concept of Materiality

The concept of 'materiality' is essential to understanding the process of verification. Chapter 2 provides a useful interpretation of the relationship between the principle of completeness and the concept of materiality. Information is considered to be material if, by its inclusion or exclusion, it can be seen to influence any decisions or actions taken by users of it. A material discrepancy is an error (for example, from an oversight, omission or miscalculation) that results in a reported quantity or statement being significantly different from the true value or meaning. In order to express an opinion on data or information, a verifier would need to form a view on the materiality of all identified errors or uncertainties. While the concept of materiality involves a value judgment, the point at which a discrepancy becomes material (materiality threshold) is usually predefined. As a rule of thumb, an error is considered to be materially misleading if its value exceeds 5% of the total inventory for the part of the organization being verified.

The verifier needs to assess an error or omission in the full context within which information is presented. For example, if a 2% error prevents a company from achieving its corporate target then this would most likely be considered material. Understanding how verifiers apply a materiality threshold will enable companies to more readily establish whether the omission of an individual source or activity from their inventory is likely to raise questions of materiality. Materiality thresholds may also be outlined in the requirements of a specific GHG programme or determined by a national verification standard, depending on who is requiring the verification and for what reasons. A materiality threshold provides guidance to verifiers on what may be an immaterial discrepancy so that they can concentrate their work on areas that are more likely to lead to materially misleading errors. A materiality threshold is not the same as *de minimis* emissions, or a permissible quantity of emissions that a company can leave out of its inventory.

8.2.3 Assessing the Risk of Material Discrepancy

Verifiers need to assess the risk of material discrepancy of each component of the GHG information collection and reporting process. This assessment is used to plan and direct the verification process. In assessing this risk, they will consider a number of factors, including:

- the structure of the organization and the approach used to assign responsibility for monitoring and reporting GHG emissions;
- the approach and commitment of management to GHG monitoring and reporting;
- development and implementation of policies and processes for monitoring and reporting (including documented methods explaining how data is generated and evaluated);
- processes used to check and review calculation methodologies;
- complexity and nature of operations;
- complexity of the computer information system used to process the information;
- the state of calibration and maintenance of meters used, and the types of meters used, if meters are required;

- reliability and availability of input data;
- uncertainty in the emission calculation methodologies;
- assumptions and estimations applied;
- aggregation of data from different sources; and
- other assurance processes to which the systems and data are subjected (e.g. internal audit, external reviews and certifications).

8.2.4 Establishing the Verification Parameters

The type of verification and the level of assurance it provides will be influenced by the company goals, verification objectives and/or any specific jurisdictional requirements. It is possible to verify the entire inventory data or specific parts of it depending on the objectives of verification. Discrete parts may be specified in terms of geographic location, activity units and facilities, and type of emissions. Defining the relevant inventory data and designing the processes for data collection and internal documentation are much easier when it is known in advance that the inventory must be verifiable. The verification process may also examine more general managerial issues, such as quality management procedures, managerial awareness, availability of resources, clearly defined responsibilities, segregation of duties, and internal review procedures.

The reporting company and the verifier should reach an agreement up-front on the level of assurance to be provided and the type of verification to be undertaken. This up-front specification addresses issues such as whether the verifier should simply review the data (Limited Assurance) or actually undertake a detailed analysis (Reasonable Assurance); and whether the verification should involve site visits or be limited to a desktop review of documentation. It may also indicate what type of information is necessary to complete the verification.

The specification should clearly state the materiality threshold (if one is to be adopted) that is applicable and the level of disaggregation that will be used during the verification. As independent verification can be an expensive and time-consuming process, it is important that the company and verifier be very clear on the type and level of verification to be performed. It is also important to determine what specific outputs the verification is intended to deliver. A verification undertaken for the purpose of identifying areas for improvement or further capacity building may differ from one directed at determining the company's compliance with a specific regime or programme (for example, compliance with the rules of an emissions trading scheme). Furthermore, a clearly defined specification for the verification is not only important to the company and verifier but also can assist external stakeholders in understanding and interpreting the findings of the verification.

8.2.5 Selecting a Verifier

The selection and engagement of a verifier can occur at various points during the GHG reporting period. Some companies may establish a semi-permanent verification unit within their organization to ensure that GHG data standards are being met and improved on an ongoing basis.

Verifications that occur during a reporting period can assist in correcting any reporting deficiencies or data issues before the final report is prepared. This may be particularly useful for companies preparing high profile public reports. However, some programmes or jurisdictions may require, often on a periodic basis, an independent verification of the reported inventory following the submission of a report (e.g. The Climate Registry). The timing and nature of the verification will depend on the purpose of the verification.

Some factors to consider when selecting a verifier include: their experience in GHG verification; their understanding of GHG issues and the company's operations; and their objectivity and independence. The knowledge and qualifications of the individual(s) conducting the verification is more important than those of the organization they come from. Effective verification of GHG inventories often requires a mix of specialized skills, particularly if the company is integrating the carbon accounts with its financial accounting system.

8.2.6 Preparing for a GHG Verification

The internal processes described in Section 8.1 are in many ways similar to those that would be followed by an independent verifier. Therefore, the materials that the verifiers will need are similar. In addition, external verifiers will want such information about the company as:

- information about the company's main activities and their GHG emissions (type of GHG produced, description of activity that causes GHG emissions); and
- company/groups/organizational particulars (e.g. details of subsidiaries and their geographic location, ownership structure, financial entities within the organization);

and other information, such as:

- consolidation of data in paper reports or electronic files;
- a list of persons responsible for collecting GHG emissions data at each site and at the corporate level (including name, title, e-mail and telephone numbers); and
- information on uncertainties, quantified or otherwise.

Appropriate evidence needs to be available to support the information in the GHG inventory being subjected to external verification. Assertions by management for which there is no available supporting evidence cannot be verified. Where a reporting organization has not yet implemented systems for routinely measuring and recording GHG emissions data, an external verification cannot be undertaken.

Reporting entities need to guarantee the existence, quality and retention of documentation so as to create an audit trail of how the inventory was compiled. If a company has established a specific base year to track emissions over time, it must retain all relevant historical records to support the base year data. Reporting entities designing and implementing the processes and procedures for creating an inventory should, therefore, make a point of creating a clear document trail.

Information that underpins GHG inventory data should be recorded in a systematic manner, for example in an electronic database. As noted in Section 8.1, some of the required information for a GHG inventory may already be in normal management/account records, or in environmental management systems such as ISO 14001 and the EU Eco-Management and Audit Scheme (EMAS). ISO 14064-3 (verification of GHG assertions) provides specific guidance on the information required for verifying GHG emissions,

Finally, prior to the commencement of an independent verification activity, it is often useful to undertake a dry run or internal 'dummy' verification to try to identify or highlight potential areas of concern or issues associated with accessing appropriate documentation. This can be a useful means of identifying and rectifying problems that would otherwise increase the cost and time required to complete the verification.

8.2.7 Using the Verification Findings

The process of verification should always be viewed as an essential input to the process of continuous improvement. Whether verification is undertaken for the purposes of internal review, for public reporting, or to certify compliance with a particular programme or regime, it will contain useful information and guidance on how, if necessary, a company's GHG measurement and reporting system can be improved and enhanced.

For those entities that have been, or are going to be, subject to verification it is important to establish internal procedures or review mechanisms that can develop and prioritize appropriate actions to overcome any discrepancies or deficiencies identified in the verification process. As is the case with the process of selecting a verifier, it is important that those responsible for assessing and implementing responses to the verification findings also have appropriate skills and understanding of GHG accounting and reporting issues. Verification reports will normally include a specific list of actions or activities that are recommended to overcome any problems identified during the verification. While recommendations for improvement are usually clear and easily understandable there may be instances when an entity is not confident about effectively dealing with the verification findings and how to implement the recommendations. In this case it can be useful to contract specialized external expertise to assist with understanding and implementing the recommendations.

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Appendix A. Glossary

Absolute target	A target defined as a reduction in absolute emissions over time, e.g. a reduction of CO_2 emissions by 25% below 1994 levels by 2010
Accounting	Recognition and consolidation of GHG emissions data
Activity	Any action or operation that causes or influences the release of GHG emissions
Aggregation	The process by which data from individual sources and/or operations are combined into a single number for a higher level entity
Base year	A historic datum (a single year or an average over multiple years) for tracking a company's emissions over time
Base year approach	The approach established for setting a base year, for example, using a fixed year or the previous year (rolling base year) to track emissions over time
Base year emissions	GHG emissions in the base year
Baseline	A hypothetical scenario for what GHG emissions, removals, or storage would have been in the absence of a GHG project or project activity
Benchmarking	The process of assessing relative performance against a group of peers
Boundary	The determination of which emissions are accounted for and reported by a company. GHG accounting and reporting boundaries can have several dimensions, i.e. organizational, operational, geographic, business unit, and other.
Cogeneration unit/combined heat and power (CHP)	A facility producing both electricity and steam or heat using the same fuel supply
Consolidation	Combination of GHG emissions data from separate operations that form part of one company or group of companies
Control approach	An approach to accounting for GHG emissions from operations that a company controls. Under the control approach, a company reports all of the emissions from operations it controls irrespective of its ownership share in those operations. Control may be defined in either financial or operational terms.
CO_2 equivalent	The mass of a greenhouse gas multiplied by its global warming potential (GWP). It is used to evaluate emissions of different

	greenhouse gases on a common basis—the mass of CO_2 emitted that would have an equivalent warming effect.
Direct GHG emissions	Emissions from sources that are owned or controlled by the reporting company
Double counting	Two or more companies taking ownership of or reporting the same emissions or emission reductions for the same purpose
Downstream	Operations involving the refining, processing, distribution and marketing of products derived from oil and gas, including service stations
Emission factor	A factor relating activity data (e.g. tonnes of fuel consumed, tonnes of product produced) and absolute GHG emissions
Emissions	The intentional and unintentional release of GHGs into the atmosphere
Equity share	The percentage of ownership or economic interest in an operation
Equity share approach	An approach for setting organizational boundaries. This approach requires reporting GHG emissions in proportion to the economic interest in or benefits derived by the reporting company from partially owned operations.
Financial control	The ability to direct the financial and operating policies of an asset with a view to gaining economic benefits from its activities.
Financial control approach	An approach for setting organizational boundaries. This approach requires reporting 100% of GHG emissions from assets that are fully consolidated and in proportion to the economic interest in the reporting company from those proportionally consolidated. See DEFRA (2009) and WRI/WBCSD (2004) for more information.
Fugitive emissions	Releases of GHGs from joints, seals, packings, gaskets, etc.
Greenhouse gases (GHGs)	For the purposes of these *Guidelines*, GHGs are the six gases (or families of gases) listed in the Kyoto Protocol: carbon dioxide (CO_2); methane (CH_4); nitrous oxide (N_2O); hydrofluorocarbons (HFCs); perfluorocarbons (PFCs); and sulphur hexafluoride (SF_6).
GHG project	A specific project or activity designed to achieve GHG emission reductions, storage of carbon, or enhancement of GHG removals from the atmosphere. GHG projects may be stand-alone projects, or specific activities or elements within a larger non-GHG related project.
GHG Protocol Initiative ***GHG Protocol***	A multi-stakeholder collaboration convened by the World Resources Institute and World Business Council for Sustainable Development to design, develop, and promote the use of accounting and reporting standards for business. It comprises two separate but linked modules—the *GHG Protocol Corporate Accounting and Reporting Standard* and the *GHG Protocol: Project Quantification Standard.*

GHG public report	A report released to the public of a company's GHG emissions for its chosen inventory boundary
GHG registry	A public database of organizational GHG emissions and/or project reductions. For example, the US Department of Energy 1605b Voluntary GHG Reporting Program and The Climate Registry.
Global Warming Potential (GWP)	A factor describing the warming potential of a given mass of a particular GHG relative to the same mass of CO_2
Heating value	The amount of energy released when a fuel is burned completely. It may be reported as higher heating value (HHV)—or gross calorific value—which includes the latent heat of vaporization of the water vapour in the combustion products, or as lower heating value (LHV)—or net calorific value—which does not include the latent heat of vaporization of the water vapour.
Indirect GHG emissions	Emissions that are a consequence of the operations of the reporting company, but occur at sources owned or controlled by another company
Intensity ratios	Ratios that express GHG emissions per unit of physical activity or unit of economic value, e.g. tonnes of CO_2 emissions per kilowatt-hour of electricity generated
Intensity target	A target defined by a reduction in the ratio of emissions and an activity metric over a specified time period, e.g. to reduce CO_2 emissions per tonne of crude oil produced by X% between 2000 and 2008
Intergovernmental Panel on Climate Change (IPCC)	International body of climate change scientists. The role of the IPCC is to assess the scientific, technical and socio-economic information relevant to the understanding of the risk of human-induced climate change.
Inventory	A quantified list of an organization's GHG emissions
Inventory boundary	An imaginary line that encompasses the direct and indirect emissions that are included in the inventory. It results from the chosen organizational and operational boundaries.
Inventory disaggregation	The process of separating or maintaining emissions data at the source level rather than summing sources to provide aggregated or total results
Inventory quality	The extent to which an inventory provides a faithful, true and fair account of the GHG emissions it is meant to represent
Kyoto Protocol	A protocol to the United Nations Framework Convention on Climate Change (UNFCCC). It set binding targets for 37 industrialized countries and the European community for limiting greenhouse gas (GHG) emissions. Once it entered into force in 2005, emissions for parties ratifying the protocol became limited for the period of 2008–2012.

Life-cycle emissions	Emissions that occur from the point of raw material extraction through the manufacture, transportation, use, and disposal of a product
Material discrepancy	An error (for example from an oversight, omission, or miscalculation) that results in the reported quantity being significantly different from the true value
Materiality threshold	A concept employed in the process of verification. It is used to determine whether an error or omission is a material discrepancy or not.
Mobile combustion	Burning of fuels by transportation devices such as cars, trucks, trains, airplanes, ships, etc.
Normalization	The process of expressing emissions relative to some measure of output, e.g. tonnes of CO_2-eq/barrels of crude oil produced
Offset	A discrete GHG reduction used to compensate for GHGs elsewhere, for example, to meet a voluntary or mandatory GHG target or cap. To avoid double counting, the reductions giving rise to the offset must occur at sources or sinks not included in the target or cap for which it is used.
Operation	A generic term used to denote any kind of business activity
Operational boundaries	The boundaries that determine the direct and indirect emissions associated with operations owned or controlled by a reporting company
Operational control	Assets that are either wholly owned and operated by a company or operated by the company under a contractual obligation to other owners or participants in the asset are under the company's operational control. When reporting GHG emissions on the basis of operational control, 100% of the emissions from such assets are included in the inventory.
Organic growth/decline	Increases or decreases in GHG emissions as a result of changes in production output, product mix, plant closures and the opening of new plants that come about through increases or decreases in business volume.
Organizational boundaries	The boundaries that determine the operations owned or controlled by the reporting company. This determination depends on the consolidation approach used (i.e. equity share or operational control approach).
Outsourcing	The contracting out of activities to other companies
Petrochemicals	The manufacture, distribution, and marketing of chemical products derived from oil and gas
Process emissions	Emissions generated from manufacturing processes, such as petroleum refining or petrochemical production

Production Sharing Agreement	An agreement between one or more oil companies and a government entity or state company in which the participating oil companies provide financing and bear the risk of exploration and production activities in exchange for a share of the production remaining after royalties (and taxes and other levies paid in oil) are paid to the government. Sometimes referred to as a **Production Sharing Contract**.
Production Sharing Contract	See **Production Sharing Agreement**
Renewable energy	Energy taken from sources that are inexhaustible, e.g. wind, water, solar, geothermal energy and biofuels
Reporting	Presenting data to internal management and external users such as regulators, shareholders, the general public or specific stakeholder groups
Rolling base year	An approach to establishing a base year for tracking emissions over time in which the base year rolls forward at regular time intervals, usually yearly, so that emissions are always compared against the previous year
Scope of work	In the context of emissions verification, an up-front specification agreed between the reporting company and the verifier that indicates the type of verification to be undertaken and the level of assurance to be provided by the verification process
Sequestration	The uptake and storage of CO_2. For example, CO_2 can be sequestered by plants and in underground or deep sea reservoirs.
Significance threshold	A qualitative or quantitative criterion used to define a significant structural change
Source	Any physical unit or process that releases GHG into the atmosphere
Stationary combustion	Burning of fuels to generate electricity, steam, heat or power in stationary equipment such as boilers, furnaces, etc.
Structural change	A change in the organizational or operational boundaries of a company that result in the transfer of ownership or control of emissions from one company to another. Structural changes include mergers, acquisitions, divestitures and outsourcing/insourcing.
Uncertainty	The range around a reported value in which the true value can be expected to fall
Upstream	Operations involving the exploration, development and production of oil and gas
Verification	The assessment of the how complete and accurate a GHG inventory is. Verifications may be conducted by independent third parties or internally.

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IPIECA

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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energy API

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.

Representing one of the most technologically advanced industries in the world, API's membership includes more than 400 corporations involved in all aspects of the oil and gas industry, including exploration and production, refining and marketing, marine and pipeline transportation and service and supply companies to the oil and natural gas industry. API is headquartered in Washington, D.C. and has offices in 27 state capitals and provides its members with representation on state issues in 33 states. API provides a forum for all segments of the oil and natural gas industry to pursue public policy objectives and advance the interests of the industry. API undertakes in-depth scientific, technical and economic research to assist in the development of its positions, and develops standards and quality certification programmes used throughout the world. As a major research institute, API supports these public policy positions with scientific, technical and economic research.

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OGP

OGP represents the upstream oil and gas industry before international organizations including the International Maritime Organization, the United Nations Environment Programme (UNEP) Regional Seas Conventions and other groups under the UN umbrella. At the regional level, OGP is the industry representative to the European Commission and Parliament and the OSPAR Commission for the North East Atlantic. Equally important is OGP's role in promulgating best practices, particularly in the areas of health, safety, the environment and social responsibility.

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