# FUGITIVE EMISSIONS FROM OIL AND NATURAL GAS ACTIVITIES


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## ABSTRACT


Fugitive emissions from oil and gas operations are a source of direct and indirect greenhouse gas emissions in many countries. Unfortunately, these emissions are difficult to quantify with a high degree of accuracy and there remains substantial uncertainty in the values available for some of the major oil and gas producing countries (e.g., Russia[1] and members of OPEC[2]). This is partly due to the types of sources being considered. Furthermore, the oil and gas industry is very large, diverse and complex making it difficult to ensure complete and accurate results. The key emission assessment issues are: (a) use of simple production-based emission factors is susceptible to excessive errors; (b) use of rigorous bottom-up approaches requires expert knowledge to apply and relies on detailed data which may be difficult and costly to obtain; and (c) measurement programmes are time consuming and very costly to perform. Nevertheless, the industry has a high profile and is very advanced technically which should facilitate the supply of high-quality data, and it is *good practice* to involve technical representatives from the industry in the development of the inventory.

The *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (*IPCC Guidelines*) provide a three-tier approach for assessing fugitive emissions from oil and gas activities. These approaches range from the use of simple production-based emission factors and high-level production statistics (i.e., Tier-1) to the use of rigorous estimation techniques involving highly disaggregated activity and data sources (i.e., Tier-3), and could include measurement and monitoring programmes. The intent is that countries with significant oil and gas industries would use the more rigorous or refined approaches, and countries with smaller industries and limited resources would use the simplest approach. However, the *IPCC Guidelines* lack definition and direction in conducting the refined approaches, and the factors available for the simplified approach are in need of further refinement and updating. In addition to that , the established IPCC reporting format contains some deficiencies and should include requirements to provide some general activity summaries and performance indicators to help put the emission results in proper perspective. Accordingly, this paper provides specific recommendations for improvements of the IPCC methodology for oil and gas systems, and generally defines *good practice* in developing these inventories (including a discussion of key issues, and specific limitations and barriers). Furthermore, it identifies relevant new emission factors and methodological advancements made since the last update of the *IPCC Guidelines*.

A summary of the major oil and gas producers is provided in Annex 1. Annex 2 contains a summary of useful conversion factors for various common oil and gas statistics. Annex 3 presents typical compositions of processed natural gas and liquefied petroleum gas.

Notwithstanding the foregoing, the basic outline of this paper is consistent with that established by the General Background Paper prepared for all Expert Group Meetings on Good Practice in Inventory Preparation. Responses to the specific issues raised therein are provided, and matters discussed during the breakout sessions


[1] Recent data summarized by Lelieveld et al. (1998) and Dedikov et al. (1999) indicates emissions from the Russian natural gas processing and transmission system are less than 1 percent of throughput (i.e., lower than previously speculated). However, uncertainties regarding emissions from other segments of the oil and gas system remain high.

[2] Eleven countries make up the Organization of Petroleum Exporting Countries (OPEC): Algeria, Indonesia, Iran, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates, Venezuela, and Iraq. Collectively, OPEC members produce about 41 percent of the world's oil and hold more than 77 percent of the world's proven oil reserves. OPEC also contains nearly all of the world's excess oil production capacity.

on oil and gas activities at the Expert Group Meeting in Prague are summarized. Overall, this process has provided an opportunity to improve and build upon the existing IPCC methodology for assessing fugitive emissions from oil and gas activities, and to establish clearer directions on how to apply the *IPCC Guidelines* for the oil and gas sector.

# 1 INTRODUCTION

The assessment of fugitive atmospheric emissions of greenhouse gases from oil and gas operations is detailed in Section 1.8 of the *IPCC Guidelines* for national greenhouse gas emission inventories. Fugitive emissions from this sector include emissions from all non-combustion sources as well as from waste gas disposal activities. Emissions from fuel combustion (including waste gas utilization) are addressed elsewhere (i.e., in Sections 1.3 to 1.5 of the *IPCC Guidelines*)[3].

In general, fugitive emissions from oil and gas activities may be attributed to the following primary types of sources:

- fugitive equipment leaks;
- process venting;
- evaporation losses;
- disposal of waste gas streams (e.g., by venting or flaring), and
- accidents and equipment failures.

Accidents and equipment failures may include well blowouts, pipeline breaks, tanker accidents, tank explosions, gas migration to the surface around the outside of wells, and surface-casing vent blows. Gas migration to the surface may be caused by a leak in the production string at some point below the surface casing, or by the migration of material from one or more of the hydrocarbon-bearing zones which are penetrated (e.g., a coal seam). A surface-casing vent blow may be caused by a leak from the production casing into the surface casing or by fluid migration up into the surface casing from below.

The following additional sources of fugitive emissions may be encountered at oil and gas facilities, but are addressed elsewhere in the *IPCC Guidelines* and, normally, are only minor contributors to greenhouse gas emissions by the oil and gas industry:

- leakage of CFCs' from refrigeration systems and $SF_6$ from electrical components (see Section 2.17 of the *IPCC Guidelines*);
- land disposal of solid waste (see Section 2.17 of the *IPCC Guidelines*);
- methane emissions from wastewater handling (see Section 2.17 of the *IPCC Guidelines*);
- methane from industrial wastewater and sludge streams (see Section 2.17 of the *IPCC Guidelines*), and
- nitrous oxide from human sewage (see Section 2.17 of the *IPCC Guidelines*).

While methane ($CH_4$) is the predominant type of greenhouse gas emitted as a fugitive emission in the oil and gas sector, noteworthy fugitive emissions of carbon dioxide ($CO_2$) and, to a much lesser extent, nitrous oxide ($N_2O$), may also occur. $CO_2$ is present as a natural constituent of most untreated hydrocarbon streams and occurs in high concentrations in some enhanced oil recovery schemes (i.e., where $CO_2$ and fireflood schemes are used). Consequently, it is a constituent of all fugitive emissions, plus noteworthy amounts of raw $CO_2$ are stripped from the produced gas at sour-gas processing and ethane extraction plants, and are subsequently discharged to the atmosphere through vents or flare systems.

Both $CO_2$ and $N_2O$ may also be produced from oxidation of the organic constituents of waste gas streams. Combustion products are only classified as fugitive emissions by the *IPCC Guidelines* when they are produced by waste-gas flaring or incineration activities. Additionally, the *IPCC Guidelines* provide for quantification of the following indirect contributors to radiative forcing: ozone precursors (namely, oxides of nitrogen [$NO_x$], non-methane volatile organic compounds [NMVOCs], carbon monoxide [CO]) and sulphur dioxide ($SO_2$). All these additional gases may occur as fugitive emissions from oil and gas activities.

## 1.1 Nature, magnitude, and distribution of source

The oil and gas sector is perhaps the most complex source category addressed in the *IPCC Guidelines*. The Guidelines divide the industry into three broad categories:

[3] The general definition of fugitive emissions given in the *IPCC Guidelines* is "an intentional or unintentional release of gases from anthropogenic activities excluding the combustion of fuels".

- oil and gas production;
- crude oil transportation and refining, and
- natural gas processing, transportation and distribution.

There is much greater diversity in the industry than what is implied in these simple groupings; particularly in the area of oil and gas production. A more detailed breakdown of the industry is provided in Table 1. Typically, the emissions potential and speciation profile varies dramatically between each of the industry segments and subcategories shown. The key factors that affect the amount of fugitive emissions from a given operation, are the amount and type of infrastructure employed, the integrity of the system, the amount of waste gas created and the incentives or requirements to control waste-gas volumes and reduce fugitive emissions. These factors, in turn, are a function of the following parameters and may vary greatly between countries, regions and even individual companies (as applicable):

- design and operating practices;
- frequency of maintenance and inspection activities;
- type, age, and quality of equipment;
- type of hydrocarbons being produced or handled and their composition;
- operating conditions;
- throughputs;
- pumping or compression requirements;
- metering requirements;
- treatment and processing requirements;
- frequency and duration of process upsets;
- sweet, sour or odourised service;
- population density near the facility;
- off-shore or on-shore operation;
- distance to market or the next downstream segment of the industry;
- market value of waste hydrocarbons;
- applicable environmental and conservation regulations, and
- pricing/economic incentives (e.g., if the cost of lost gas is passed on to the customer there is no incentive for gas companies to reduce methane losses).

Regulations and pricing/economic incentives are usually the most significant factors affecting the amount of fugitive emissions from venting and flaring. Emissions from fugitive equipment leaks are proportional to the amount of process infrastructure and are a general reflection of the quality of the equipment components, and inspection and maintenance programmes. Typically, the amount of emissions from fugitive equipment leaks is lowest where the process fluid is highly toxic (e.g., contains $H_2S$) or has been odourised.

Most of the fugitive greenhouse gas emissions from the oil and gas systems are methane losses from production activities, natural gas processing, transportation and distribution. The amount of fugitive emissions per unit of throughput tends to decrease downstream through both types of systems (for example, specific fugitive emissions of greenhouse gases are usually much greater from gas production than gas distribution).

Although the NMVOCs are not the specific focus of this paper, oil systems and gas systems are also significant sources of these gases. $SO_2$ emissions are attributed to the flaring or incineration of sour waste gas and acid gas streams, and to inefficiencies in sulphur recovery units at sour gas processing plants, upgraders and refineries. CO emissions are a product of all flaring and incineration activities.

**TABLE 1**

**MAJOR CATEGORIES AND SUBCATEGORIES IN THE OIL AND GAS INDUSTRY**

| Industry Segment | Sub-Categories |
|---|---|
| Wells | • Drilling<br>• Testing<br>• Servicing |
| Gas Production | • Dry Gas[1]<br>• Sweet Gas[2]<br>• Sour Gas[3] |
| Gas Processing | • Sweet Gas Plants<br>• Sour Gas Plants<br>• Deep-cut Extraction Plants |
| Gas Transmission & Storage | • Pipeline Systems (including all associated surface facilities).<br>• Storage Facilities |
| Gas Distribution | • Rural Distribution<br>• Urban Distribution |
| Natural Gas Liquids Transport | • Condensate<br>• Liquefied Petroleum Gas (LPG)<br>• Liquefied Natural Gas (LNG) (including associated liquefaction and gasification facilities) |
| Oil Production | • Conventional Oil<br>• Heavy Oil (Primary Production)<br>• Heavy Oil (Enhanced Production)<br>• Crude Bitumen<br>• Synthetic Crude Oil (From Oilsands)<br>• Synthetic Crude Oil (From Oil Shales) |
| Oil Upgrading | • Crude Bitumen<br>• Heavy Oil |
| Waste Oil Reclaiming | • None |
| Oil Transport | • Marine<br>• Pipelines<br>• Tanker Trucks and Rail Cars |
| Oil Refining | • Heavy Oil<br>• Conventional and Synthetic Crude Oil |

[1] Dry gas is natural gas that does not require any hydrocarbon dew-point control to meet sales gas specifications. However, it may still require treating to meet sales specifications for water and acid gas (i.e., $H_2S$ and $CO_2$) content. Dry gas is usually produced from shallow (less than 1000 m deep) gas wells.

[2] Sweet gas is natural gas that does not contain any appreciable amount of $H_2S$ (i.e., does not require any treatment to meet sales gas requirements for $H_2S$).

[3] Sour gas is natural gas that must be treated to satisfy sales gas restrictions on $H_2S$ content.

## 1.2 The current state of inventory methodologies

The *IPCC Guidelines* have a three-tier approach for estimating fugitive emissions from oil and gas activities:

- Tier 1: Top-down Average Emission Factor Approach;
- Tier 2: Mass Balance Approach, and
- Tier 3: Rigorous Bottom-up Approach.

A brief summary of these approaches is provided below for easy reference. Specific recommendations for changes to these approaches are provided in Sections 2 and 3.

In quantifying direct greenhouse gas emissions, the methodologies for all three tiers and the accompanying sample calculation sheets provided in the IPCC Workbook only account for methane. The tables do not account for fugitive $CO_2$ and $N_2O$ emissions. Moreover, tables are only provided to account for emissions of indirect greenhouse gases (CO, $NO_x$, NMVOCs, and $SO_2$) by refineries and sulphur recovery units at gas processing plants, and not by any other segments of the oil and gas industry.

Tier 1 is the simplest as well as the least reliable approach. It is a top-down approach in which usually average production-based emission factors are applied to reported oil and gas production volumes. This method is intended for use by countries with very limited oil and gas industries, and with limited resources to develop more reliable estimates. It is, at best, an order-of-magnitude approach, and should only be used as a last resort. It should not be applied by countries with large oil and gas industries. However, it may be reasonable to use derived average production-based emission factors to interpolate or make small extrapolations from years in which rigorous assessments have been conducted.

Tier 2 is a mass balance approach. It is primarily intended for application to oil systems where the majority of the associated and solution gas production is vented or flared. In these cases, the total amount of associated and solution gas produced with the oil is assessed, and then control factors are applied to the results to account for conserved, reinjected and utilized volumes. The result is the amount of gas either flared or lost directly to the environment (whether through equipment leaks, evaporation losses or process venting). The flared, utilized and conserved volumes are determined from available production accounting data and engineering estimates. The rest of the gas, by difference, is lost directly to the atmosphere. The reliability of this approach increases as the portion of the total gas conserved, utilized, or reinjected decreases. The total amount of associated gas per unit volume of oil production is given by the gas-to-oil ratio (GOR) for the target oil fields. The amount of solution gas or product volatilization per unit oil production is determined from the change in product vapour pressure between the inlet separator at the field production facility (i.e., the vessel operating pressure) and the refinery inlet (e.g., a Reid vapour pressure of 30 to 55 kPa).

Although the simple mass balance using national production statistics is a crude indicator of fugitive methane losses, it offers a greater degree of confidence than that offered by the Tier-1 approach. In such cases, the net balancing or reconciliation term (i.e., unaccounted for losses) may be used as an indication of total fugitive emissions from non-venting or flaring sources.

Tier 3 relies on the rigorous assessment of emissions from individual sources using a bottom-up approach, and requires both process infrastructure data and detailed production accounting data. It may also include actual measurement work as well. The results are then aggregated to determine the total emissions. The majority of the Parties currently reporting fugitive emissions from oil and gas activities are applying Tier-3 methods. However, the *IPCC Guidelines* do not establish criteria for conducting the individual source assessments. Rather, they refer the reader to several recently published emission inventories for the oil and gas sector that are deemed to be representative of a rigorous bottom-up approach. Consequently, there is a wide range in what potentially may be classified as a Tier-3 approach, and correspondingly, in the amount of uncertainty in the results.

# 2 METHODOLOGICAL ISSUES

## 2.1 Selection of *Good Practice* methods

*Good practice* is to disaggregate the industry into the applicable segments and subcategories indicated in Table 1, and then evaluate the emissions separately for each of these. The approach selected in each case should be commensurate with the amount of emissions and the resources available for assessing these emissions. Consequently, it may be appropriate to apply different approaches to different parts of the industry, and possibly even include some direct monitoring of emission sources. The overall approach, over time, should be one of progressive refinement to address the areas of greatest uncertainty as well as capturing the impact of specific control measures.

A recommended framework for developing national inventories of fugitive emissions from oil and gas activities is as follows:

- Decide on the appropriate level of analysis based on the expected amount of emissions and their significance compared to the values for other sectors in the country and to total global anthropogenic emissions of greenhouse gases. Compile the input data required for application of the selected assessment approach or approaches (e.g., emission factors, activity and infrastructure data, control factors, and gas analyses), and document the sources and quality of these data;

- Estimate the emissions and check the results for possible errors and anomalies and make any appropriate adjustments or corrections;
- Determine the largest sources and those that contribute most to uncertainty in the total inventory, and
- Assess the need to apply more refined approaches to specific key sources and revise the inventory accordingly.

The specific factors which need to be considered in selecting an appropriate assessment approach are as follows:

- The use of a Tier-1 approach implies a reasonable correlation between production or throughput volumes and fugitive emission levels. This may be valid for systems with high venting and flaring emissions. However, for well-controlled systems the dominant source of emissions will tend to be fugitive equipment leaks, which are generally independent of system throughputs;
- The ability to account for specific control measures will become more important as Parties strive to meet their emission reduction targets. A Tier-1 approach only captures the impact of any changes in gross activity levels. A Tier-2 or -3 approach must be used in order to show the impact of site-specific vapour and waste-gas control measures. To show changes in emissions from fugitive equipment leaks (a large if not the largest source of organic emissions at many facilities) requires the performance of regular leak detection and repair programmes. Furthermore, conventional technologies used in leak detection and repair programmes (i.e., estimation of leak rates based on leak screening data collected in accordance with US EPA's Method 21) provide only a very crude indication of actual changes in emissions. According to Lott et al. (1996), the typical error from use of such approaches is ±300 percent or more depending on the number of components considered and the actual method used to estimate leak rates from the screening values (i.e., emission factors or leak-rate correlations). Since nearly all the emissions come from the small percentage of components that leak the most, a good approach might be to conduct a simplified screening programme to identify these few leaks and then use direct measurement techniques (e.g., High-Flow sampler [Lott et al., 1996], flow-through flow meters, and bagging techniques) to accurately measure their actual leak rates (also see Section 2.2.3);
- While optimizing the quality of the inventory dictates that efforts be focused on the areas of greatest uncertainty, capturing the impact of control measures may require the application of efforts in other areas. For instance, specific fugitive emission rates and uncertainty levels tend to increase upstream in oil and gas systems, while the value of the gas, and to a certain extent, the cost effectiveness of implementing emission reduction measures, tends to increase in the opposite direction. However, in general, the value of avoided hydrocarbon losses is very site-specific and depends on many factors which include the following:

  (i) Value of the hydrocarbons in terms of invested costs up to the point of control (i.e., costs, as applicable, to find, produce, treat, upgrade, refine or process, and deliver the sales product);

  (ii) Capital and operating costs to achieve the proposed emission reductions compared to the costs to find and develop new gas supplies;

  (iii) Supply and demand constraints. Often the conserved gas becomes reserve production that is not sold until reservoir and market conditions change to the point where demand exceeds supply. Thus, the economic benefit of avoided losses may not be realized until near the end of the project life when the avoided gas losses are finally sold, and

  (iv) Applicable government taxes, royalties, subsidies and incentives.
- There have been numerous and substantial advancements in recent years in the available methods for conducting Tier-3 source-specific emission assessments. A summary of the available options and a discussion of the limitations and merits of each are provided by CAPP (1999). The different assessment techniques may be classified as follows:

  (i) **Activity-based Emission and Control Factors**: these are more refined emission factors than those applied in the Tier-1 approach. They include, but are not limited to, factors for estimating the combustion products from flares (US EPA, 1995a, GRI Canada, 1999), emissions from fugitive equipment leaks (GRI Canada, 1998; U.S. EPA, 1995a,b; GRI, 1996; API, 1993, 1995, 1996, 1998; CAPP, 1992, 1999; CCME, 1993; Nordic Gas Technology Center, 1993; Radian, 1996; Rose, 1993), solution gas emissions from oil emulsion treaters and production storage tanks (CAPP, 1992, 1999), and gas consumption by gas-operated devices (e.g., chemical injection pumps, process samplers and analyzers, and instrument control loops) (CAPP, 1992, 1999; Radian, 1996). Additional sources of factors for oil and gas systems include Onook and Vosbeek (1995) and Schneider-Fresenius et al. (1989);

(ii) **Empirical Correlations:** examples of empirical correlations include the various API (1997, 1996, 1991, 1987) algorithms for determining evaporation losses from storage tanks and product loading/unloading terminals, and leak-rate correlations for converting leak screening data to emissions rates (GRI Canada, 1998; US EPA, 1995b);

(iii) **Computer Models and Simulators**: these are software applications which utilize rigorous engineering principles and calculation methods (e.g., mass, momentum and energy transfer, thermodynamics and chemical kinetics) to estimate emissions based on specific physical, operating and activity parameters of the target source. Examples include GRI-GLYCalc (Thompson et al., 1994) for estimating still-column off-gas emissions from glycol dehydration units, E&P-TANK (DB Robinson Research Ltd., 1997) for calculating flashing and evaporation losses from production storage tanks, TANKS 3.1 (U.S. EPA, 1997) for predicting evaporation losses from tanks containing stable products (i.e., based on the API correlations for evaporation losses), as well as a range of commercial process and emission-source simulation packages;

(iv) **Direct Measurement Techniques**: these techniques include duct or stack flow measurements, bagging (US EPA, 1995b), high-flow sampler (Lott et al., 1996), isolation flux chambers (Kienbusch and Ranum, 1986; Kiennbusch, 1986), and portable wind tunnels (Schulz et al., 1995; Jiang and Kaye, 1997). The latter two methods are applicable for measuring volatilization rates from sources such as exposed oilsands, contaminated soils and landfarm operations. Overall, direct methods tend to offer the greatest potential accuracy but are only amenable to relatively simple point sources or applications where a high degree of specificity is required, and

(v) I**ndirect Measurement Techniques:** these include remote sensing (Scotto et al., 1991; Piccot et al., 1996; Minnich et al. 1991), the plume transect method (Mickunas et al., 1995; Piccot et al., 1996; Balfour and Schmidt, 1984), and tracer methods (McManus et al., 1994; Lamb et al., 1995, 1994). Indirect methods are best suited for a lumped-analysis of large complex sources.

- Many of the Tier-3 methods require the use of experienced well-trained personnel or specialists to achieve reliable results. Moreover, they require either very detailed site-specific data or the performance of actual field measurements. The use of these refined approaches allows greater disaggregation of the emissions, and in turn, facilitates better interpretation of the results. It also allows more meaningful intra- and inter-national comparisons with corresponding specific emission rates in other regions;
- It is important to achieve proven, transparent results, account for specific control measures and understand the uncertainties in the developed results. However, the cost of achieving such results should not become a significant burden on resources available to reduce emissions. Focused (or optimized) measurement and monitoring programmes should be conducted to confirm calculated emissions and emission reductions where such values are significant, and
- Some industry associations have been developing comprehensive handbooks for use by member companies in assessing their emissions. The key objectives for a number of these initiatives have been to provide a flexible framework in which individual companies may assess their emissions, and to establish a base set of terms, source categories and nomenclature to facilitate inter-company comparisons and allow easy aggregation of the results for rollup into national emission inventories. GRI Canada (1998 and 1999) has recently prepared two such handbooks for application to gas transmission, storage and distribution systems. API (1996) has developed a calculation workbook for oil and gas production equipment fugitive emissions. CAPP (2000) has prepared a document for upstream oil and gas operations.

In addition, there are several commercial software packages available for developing and maintaining Tier-3 emission inventories.

Updates to the inventory should, at a minimum, match critical baseline and milestone years specified in the agreements by the Parties to the United Nations Framework Convention on Climate Change (UNFCCC). However, more frequent updates will allow Parties to track their progress in achieving targeted reductions, and allow progressive refinement of the results (i.e., to continually refocus efforts based on the findings of the preceding efforts). In general, the frequency of updates should reflect the rate of change in emissions.

## 2.2 Emission factors

Average emission factors, typically, are developed and published by environmental agencies and industry associations. They are statistical values that may be expected to provide reasonable results when applied to a large population of applicable sources (e.g., for regional and national emission inventories). They are not intended for application to individual or small numbers of sources.

The reliability of an emission factor in a given application depends on the quality of the factor, the specific pollutants of interest, and the type of source. Emission factors are continually being updated to include additional measurement results and to reflect development and penetration of new control technologies as well as impacts of increasing performance standards and regulatory control requirements. Accordingly, regular reviews should be conducted to ensure that the best available factors are being used, and the references for the chosen values should be clearly documented. Since emission factors are developed and published by environmental agencies and industry associations, it then becomes necessary to develop inventory estimates in consultation with these organizations.

The selected emission factors must be valid for the given application and be expressed on the same basis as the activity data. In some cases, it may be appropriate to apply speciation profiles and factors to account for the amount of time a source is active and for specific control measures being used.

The following are additional considerations to be taken into account in choosing emission factors:

- It is important to assess the applicability of the selected factors for the target application to ensure similar/comparable source behaviour and characteristics;
- In the absence of better data, it may sometimes be necessary to apply factors reported for other regions. However, tests should ultimately be performed to verify the validity of these selections, and
- Where measurements are performed to develop new emission factors, only recognized or proven test procedures should be applied. The methodology and quality control (QC)/ quality assurance (QA) procedures should be documented and the sampled sources should be representative of typical variations in the overall source population. Uncertainties and limitations of the results should be also assessed.

## 2.2.1 Tier1 emission factors

The current Tier-1 emission factors provided in the *IPCC Guidelines* are production-based factors. They are presented as a function of the geographic area and the type of oil and gas activity. In each case, these factors are expressed as a range of values rather than a single number. This provides some indication of the potential uncertainties and variability in the emission factor values.

However, where a Tier 1 approach is appropriate, emission factors of the form presented in Tables 2 and 3 should be used in favour of those given in the *IPCC Guidelines*. Although still a crude means of estimating fugitive emissions, the new factors allow for improved correlation of emissions with commonly-available activity data and may be expected to generally limit uncertainties to within an order of magnitude. The improved correlations are achieved through increased disaggregation of the industry and, in several cases, by switching to different activity parameters. For example, fugitive emissions from gas transmission and distribution systems do not correlate well with throughput, and are better related to lengths of pipeline.

The new factors are derived from detailed emission inventory results for Canada and the United States, and are presented as examples only. Notwithstanding this, these values may be applied to regions outside of North America that practice similar levels of emissions control and feature comparable types and quality of equipment. Even where moderate regional differences exist, the new factors may still offer more reliable results than those obtained from use of the factors given in the *IPCC Guidelines*. Nonetheless, it is good practice to consider the impact of regional differences before adopting a specific set of factors. In the absence of data for a particular industry segment, the emission factors given in the IPCC *Guidelines* should be used.

Additional opportunities for improvements to the *IPCC Guidelines* are provided below:

- The *IPCC Guidelines* apply a single factor for assessing the emissions from combined flaring and venting activities. The split between vented volumes and flared volumes is particularly susceptible to change as Parties pursue their emission reduction targets. Accordingly, separate factors should be provided for each type of release;
- Currently, greenhouse gas emission factors are only provided for methane. Factors should also be provided for estimating raw $CO_2$ emissions, and $CO_2$ and $N_2O$ combustion emissions from incineration or flaring of waste gases, and
- Emission factors for indirect greenhouse gases (i.e., ozone precursors and $SO_2$) should be provided for the same level of specificity as the direct greenhouse gases. The factors currently provided for ozone precursors only account for such emissions from refineries and not from other oil and gas activities (collectively, a much greater source). The $SO_2$ factors account for such emissions from sulphur recovery units at gas processing plants and oil refineries, but do not account for $SO_2$ emissions from flaring of sour waste gas and acid gas streams. This may be a significant additional source of $SO_2$ for some Parties.

### 2.2.2 Emission factor values in literature

For a given segment and subcategory of the oil and gas industry there may be many similarities in emissions between one region or geographic area and another. However, there also may be many differences. In the absence of better data, it may be necessary to assume corresponding values reported for other regions, but ultimately, tests should be performed to verify the validity of these selections. In some countries government agencies, industry associations, and even individual companies are currently undertaking such initiatives, and developing their own factors as warranted (see Tables 2 and 3).

Many of the recent sources of emission factors are referenced in Section 2.1.

**TABLE 2**

**REFINED PRODUCTION-BASED TIER-1 EMISSION FACTORS BASED ON CANADIAN DATA**

| Category | Sub-category | Default emission factor | | | Units of measure |
|---|---|---|---|---|---|
| | | $CH_4$ | $CO_2$ | $N_2O$ | |
| Wells | Drilling | 4.3E-07 | 2.8E-08 | 0 | Gg per number of wells drilled |
| | Testing | 2.7E-04 | 5.7E-03 | 6.8E-08 | Gg per number of wells drilled |
| | Servicing | 6.4E-05 | 4.8E-07 | 0 | Gg/y per number of producing and capable wells |
| Gas Production | All | 3.1E-03 | 1.9E-03 | 2.2E-08 | Gg per $(10^6)$ $m^3$ gas production |
| Gas Processing | Sweet Gas Plants | 7.1E-04 | 3.9E-03 | 4.6E-08 | Gg per $(10^6)$ $m^3$ gas receipts |
| | Sour Gas Plants | 2.4E-04 | 7.5E-02 | 5.4E-08 | Gg per $(10^6)$ $m^3$ gas receipts |
| | Deep-cut Extraction Plants | 7.2E-05 | 2.1E-06 | 0 | Gg per $(10^6)$ $m^3$ gas receipts |
| Gas Transmission & Storage | Transmission | 3.4E-03 | 0 | 0 | Gg per km of transmission pipeline |
| | Storage | 8.4E-04 | 0 | 0 | Gg per $(10^6)$ $m^3$ gas stored |
| Gas Distribution | All | 5.2E-04 | 0 | 0 | Gg per km of distribution mains |
| Natural Gas Liquids Transport | Condensate | 1.1E-04 | 7.2E-06 | 0 | Gg per $(10^3)$ $m^3$ Condensate and Pentanes Plus |
| | Liquefied Petroleum Gas | 0 | 4.3E-04 | 2.2E-09 | Gg per $(10^3)$ $m^3$ NGL |
| | Liquefied Natural Gas | NA | NA | NA | Gg per $(10^6)$ $m^3$ gas handled. |
| Oil Production | Conventional Oil | 1.8E-03 | 6.8E-02 | 6.4E-07 | Gg per $(10^3)$ $m^3$ conventional oil production |
| | Heavy Oil | 2.2E-02 | 4.9E-02 | 4.7E-07 | Gg per $(10^3)$ $m^3$ heavy oil production |
| | Crude Bitumen | 1.2E-03 | 2.4E-02 | 2.4E-07 | Gg per $(10^3)$ $m^3$ crude bitumen production |
| | Synthetic Crude (Oilsands) | 2.3E-03 | 0 | 0 | Gg per $(10^3)$ $m^3$ synthetic crude production from oilsands |
| | Synthetic Crude (Oil Shale) | NA | NA | NA | Gg per $(10^3)$ $m^3$ synthetic crude production from oil shale |
| Oil Upgrading | All | ND | ND | ND | Gg per $(10^3)$ $m^3$ oil upgraded |
| Oil Transport | Pipelines | 5.4E-06 | 4.9E-07 | 0 | Gg per $(10^3)$ $m^3$ oil transported by pipeline |
| | Tanker Trucks and Rail Cars | 2.5E-05 | 2.3E-06 | 0 | Gg per $(10^3)$ $m^3$ oil transported by Tanker Truck |

NA - Not Applicable

ND - Not Determined

Source: Derived from Canadian Association of Petroleum Producers. 1999. "CH4 and VOC Emissions from the Canadian Upstream Oil and Gas Industry", Calgary, Alberta.

**TABLE 3**

**RFINED PRODUCTION-BASED TIER-1 EMISSION FACTORS BASED ON US DATA**

| Category | Sub-Category | Default emission factor | | | Units of Measure |
|---|---|---|---|---|---|
| | | $CH_4$ | $CO_2$ | $N_2O$ | |
| Wells | Drilling | ND | ND | ND | Gg per number of wells drilled |
| | Testing | ND | ND | ND | Gg per number of wells drilled |
| | Servicing | ND | ND | ND | Gg/y per number of producing and capable wells |
| Gas Production | All | 2.49E-03 | 0 | 0 | Gg per ($10^6$) $m^3$ gas production |
| Gas Processing | All | 9.0E-04 | 0 | 0 | Gg per ($10^6$) $m^3$ gas receipts |
| Gas Transmission & Storage | Transmission | 3.7E-03 | 0 | 0 | Gg per km of transmission pipeline |
| | Storage | 5.8E-03 | 0 | 0 | Gg per ($10^6$) $m^3$ gas stored |
| Gas Distribution | All | 7.1E-04 | 0 | 0 | Gg per km of distribution mains |
| Natural Gas Liquids Transport | Condensate | ND | ND | ND | Gg per ($10^3$) $m^3$ Condensate and Pentanes Plus |
| | Liquefied Petroleum Gas | ND | ND | ND | Gg per ($10^3$) $m^3$ NGL |
| | Liquefied Natural Gas | ND | ND | ND | Gg per ($10^6$) $m^3$ gas handled. |
| Oil Production | Conventional Oil | ND | ND | ND | Gg per ($10^3$) $m^3$ conventional oil production |
| | Heavy Oil | ND | ND | ND | Gg per ($10^3$) $m^3$ heavy oil production |
| | Crude Bitumen | NA | NA | NA | Gg per ($10^3$) $m^3$ crude bitumen production |
| | Synthetic Crude (Oilsands) | NA | NA | NA | Gg per ($10^3$) $m^3$ synthetic crude production from oilsands |
| | Synthetic Crude (Oil Shale) | NA | NA | NA | Gg per ($10^3$) $m^3$ synthetic crude production from oil shale |
| Oil Upgrading | All | ND | ND | ND | Gg per ($10^3$) $m^3$ oil upgraded |
| Oil Transport | Pipelines | ND | ND | ND | Gg per ($10^3$) $m^3$ oil transported by pipeline |
| | Tanker Trucks and Rail Cars | ND | ND | ND | Gg per ($10^3$) $m^3$ oil transported by Tanker Truck |

NA - Not Applicable

ND - Not Determined

Source: Derived from GRI/US EPA. 1996. "Methane Emissions from the Natural Gas Industry", Report No. EPA-600/R-96-080.

## 2.2.3 Measurement and monitoring programmes

Routine measurement or monitoring of fugitive emissions is sometimes a regulatory requirement in certain sections of the oil and gas industry (i.e., at refineries). But generally it is not feasible for the rest of the industry (i.e., due to the specific costs, the large number and distribution of these sources amongst many widely dispersed facilities) to put this in operation except where efforts can be focused on problem sources.

Where measurements are performed to develop new emission factors, only recognized or proven test procedures should be applied, the methodology and QA/QC procedures should be documented, the sampled sources should be representative of the variations in the overall source population, and a statistical analysis of the results should be conducted to establish the 95 percent confidence limits on the average results.

The available measurement techniques for assessing fugitive emissions may be characterized as either direct or indirect and are listed in Section 2.1 of this paper. Direct methods involve the physical measurement of flow rates and gas concentrations at the source. Indirect measurement techniques rely on the use of a theoretical or empirical model to back-calculate a source strength based on pollutant concentrations at a convenient downwind reference point, and on appropriate process-activity and/or meteorological data.

Typically, the key advantages of direct methods over comparable indirect methods include:

- improved sensitivities or detection limits;
- easier-to-assess uncertainties;
- more accurate and disaggregated results allowing better identification and evaluation of specific emission reduction opportunities;
- fast, low-cost means of determining emissions from a few simple point sources;
- simple, easy-to-operate measurement equipment;
- simple data reduction, and
- ability to isolate and measure emissions from a target source in the presence of other nearby sources to avoid interference problems.

The key advantages of indirect methods usually include:

- ability to safely determine emissions from hazardous or difficult-to-access sources;
- all the emissions are measured so there are no missed sources;
- fast, low-cost means of determining aggregate emissions from large complex area or volume sources,
- measurements can be performed off-site, and
- applicable to a wide variety of sources.

Some of the main disadvantages of indirect methods are as follows:

- relies heavily on favourable meteorological conditions and downwind terrain;
- susceptible to interferences from other nearby sources;
- requires the ability to detect small concentration changes of analytes at very low levels;
- generally requires greater expertise and quality assurance/quality control (QA/QC) measures than direct methods;
- large potential errors depending on circumstances and the technique being applied (e.g., emission estimates for simple point sources may have errors of ±10 to 25 percent under favourable conditions, while estimates for more complex sources and conditions may easily be in error by several orders of magnitude; furthermore, the true emission rate is never really known unless appropriate confirmation measurements are performed which may be difficult and costly to do on large, complex sources);
- often more expensive than direct methods when only applied to small or medium sized facilities (due to more complex test and QA/QC procedures and the use of more expensive equipment), and
- emissions are aggregated so the key contributors or opportunities for emission reduction are not known.

The best approach for a given application depends on the specific objectives to be achieved. Often a staged approach may be warranted. Initially, an indirect approach may be used to provide a rough estimate of total emissions from a facility or operation. It may be necessary to separate flue emissions from fugitive emissions, and to separate vent stack emissions from ground-based emissions. If warranted, screening methods may then be used to identify emission hot spots at the facility, and ultimately, to develop a list of potential problem emission sources. Finally, direct techniques may be used to determine actual emissions from the identified key sources. These results may be used to help evaluate the feasibility of undertaking specific mitigation actions, and to prioritize such efforts.

However, it should be noted that most measurement techniques provide only a brief snapshot of the emissions. If total fugitive emissions from a facility or source are highly variable (e.g., on a diurnal or seasonal basis), a series of measurement campaigns may be required to provide a reliable assessment. Also, it may be important to either isolate or properly account for possible interferences from the plumes of other nearby sources. Often, portable, fast-response analyzers (e.g., for methane or hydrogen sulphide) may be used to visualise and verify separation of plumes in real time.

## 2.3 Activity data

The activity data required to assess fugitive emissions from oil and gas activities may include production statistics, infrastructure data (e.g., inventories of facilities/installations, process units, pipelines, and equipment components), and reported emissions from spills, accidental releases, and third-party damages. The basic activity data required for each assessment Tier and each type of primary source are summarized in Table 4.

### 2.3.1 Production statistics

Specific matters to consider in compiling national or regional production statistics are as follows:

- The production statistics should be disaggregated to capture changes in throughputs (e.g., due to imports, exports, reprocessing, withdrawals, etc.) in passing through oil and gas systems;
- If data are drawn from several different sources, it must be ensured there is no double or missed counting of emissions due to differences in terminology and classifications, and
- Production statistics or disposition analysis do not necessarily agree between different reporting agencies even though they are based on the same original measurement results (e.g., due to possible differences in terminology and potential errors in summarizing these data). These discrepancies may be used as an indication of the uncertainty in the data. Additional uncertainty will exist if there is any inherent bias in the original measurement results (for example, sales meters are often designed to err in favour of the customer, and liquid handling systems will have a negative bias due to evaporation losses). Random metering and accounting errors may be assumed to be negligible when aggregated over the industry.
- Production statistics provided by national bureaus should be used in favour of those available from international bodies, such as IEA or the UN, due to their generally better reliability and disaggregation. Regional, provincial/state and industry reporting groups may offer even more disaggregation.
- Reported vented and flare volumes are highly suspect since these values are usually estimates and not based on actual measurement results. Additionally, the values are often aggregated and simply reported as flared volumes.

Operating practices of each segment of the industry should be reviewed to determine if the reported volumes are actually vented or flared, or to develop appropriate proration factors. Furthermore, audits or reviews of each industry segment should be conducted to determine if all vented/flared volumes are actually reported (for example, solution gas emissions from storage tanks and treaters, emergency flaring/venting, leakage into vent/flare systems, and blowdown and purging volumes may not necessarily be accounted).

Some production statistics may be reported in units of energy (based on their heating value) and need to be converted to a volume basis, or vice versa, for application of the available emission factors. Typically, where production values are expressed in units of energy, it is in terms of the gross (or higher) heating value of the product. However, where emission factors are expressed on an energy basis it is sometimes in terms of the net (or lower) heating value of the product (especially factors provided by equipment manufacturers). Accordingly, it must be ensured that the emission factors and activity data are on a consistent basis.

### 2.3.2 Data infrastructure

Infrastructure data (primarily required for Tier 3 approaches) is much less available than production statistics. Notwithstanding this, information concerning the numbers and types of major facilities and the types of processes used at these facilities may often be available from regulatory agencies and industry groups, or directly from the oil and gas companies. Therefore, it is good practice to involve technical representatives from these organizations in the development of the inventory.

Information on minor facilities (e.g., numbers of field dehydrators and field compressors) usually is not available, even from the oil and gas companies. Consequently, assumptions must be made, based on local design practices, to estimate the numbers of these facilities. This may require some fieldwork to develop appropriate estimation factors or correlations.

| TABLE 4<br>TYPICAL ACTIVITY DATA REQUIREMENTS FOR EACH ASSESSMENT APPROACH BY TYPE OF PRIMARY SOURCE CATEGORY | | |
|---|---|---|
| **Assessment Tier** | **Primary Source Category** | **Minimum Required Activity Data** |
| 1 | All | • Oil and Gas Throughputs |
| 2 | Oil Systems | • Gas to Oil Ratios<br>• Flared and Vented Volumes<br>• Conserved Gas Volumes<br>• Reinjected Gas Volumes<br>• Utilized gas Volumes<br>• Gas Compositions |
| 3 | Process Venting/Flaring | • Reported Volumes<br>• Gas Compositions<br>• Proration Factors for Splitting Venting from Flaring |
| | Storage Losses | • Solution Gas Factors<br>• Liquid Throughputs<br>• Tank Sizes<br>• Vapour Compositions |
| | Equipment Leaks | • Facility/Installation Counts by Type<br>• Processes Used at Each Facility<br>• Equipment Component Schedules by Type of Process Unit<br>• Gas/vapour Compositions |
| | Gas-Operated Devices | • Schedule of Gas-operated Devices by Type of Process Unit<br>• Gas Consumption Factors<br>• Type of Supply Medium<br>• Gas Composition |
| | Accidental Releases & Third-Party Damages | • Incident Reports/Summaries |
| | Gas Migration to the Surface & Surface Casing Vent Blows | • Average Emission Factors & Numbers of Wells |
| | Drilling | • Number of Wells Drilled<br>• Reported Vented/Flared Volumes from Drill Stem Tests<br>• Typical Emissions from Mud Tanks |
| | Well Servicing | • Tally of Servicing Events by Types |
| | Pipeline Leaks | • Type of Piping Material<br>• Length of Pipeline |
| | Exposed Oilsands/ Oil Shale | • Exposed Surface Area<br>• Average Emission Factors |

Many companies use computerized inspection-and-maintenance information management systems. These systems can be a very reliable means of counting major equipment units (e.g., compressor units, process heaters and boilers, etc.) at selected facilities. Also, some departments within a company may maintain databases of certain types of equipment or facilities for their own specific needs (e.g., tax accounting, production accounting, insurance records, quality control programs, safety auditing, license renewals, etc.). Some efforts should be made to identify these potentially useful pools of information.

Component counts by type of process unit may vary dramatically between Parties due to differences in design and operating practices. Thus, while initially it may be appropriate to use values reported in the general literature, Parties should ultimately consider developing their own values.

Use of consistent terminology and clear definitions is critical in developing counts of facilities and equipment components, and to allow any meaningful comparisons of the results.

## 2.3.3 Additional data for refined approaches

The activity data required for refined (i.e., Tier 2 and 3) emission-assessment approaches may include the following:

- process operating conditions (e.g., gas compositions, temperatures, pressures and flows);
- maintenance records;
- accident reports;
- tallies and details of blowdown events, compressor starts and purging activities;
- inventories of gas-operated devices that use natural gas as the supply medium (e.g., instrument control loops, chemical injection pumps, automatic samplers);
- facility or installation counts by type;
- process unit counts by type;
- gas-to-oil ratios;
- number and types of wells drilled, tested and serviced;
- number of pipeline tie-ins resulting in blowdown and purging events;
- pigging frequencies per pipeline system;
- production rates;
- vented volumes;
- flared volumes;
- population, sizes and service of storage tanks, and
- equipment component counts on a process unit and facility basis.

Additional data that may be needed are listed below:

- length of each pipeline and type of pipe material used (e.g., steel, cast iron, aluminum, orplastic);
- emissions control measures;
- gas-to-oil ratios;
- sweet, sour, or odourised service, and
- operating practices (e.g., depressurization of idle compressors, flaring rather than venting, etc.).

Some of the key considerations in obtaining and using refined activity data are as follows:

- Often, much of the required data for a refined assessment is difficult and costly to obtain or are simply unavailable. Consequently, some assumptions may be needed to bridge certain information gaps;
- Except for oil refining and gas processing, the oil and gas industry tends to be characterized by many small facilities and minor installations rather than a few large facilities as in other industries. Detailed inventories of the major facilities (i.e., gas plants and refineries) usually are available from regulatory agencies and some industry groups and periodicals (often in a convenient electronic format). However, information on minor field installations (e.g., field dehydrators, compressor stations, line heaters, meter stations, regulator stations, pigging stations, mainline block valves, satellite batteries, etc.) often does not exist or is difficult to obtain. Consequently, in areas where there are large, complex oil and gas industries, the emission inventories will be susceptible to significant errors due to missed or unaccounted sources. To minimize such errors it is important to obtain active industry involvement in the preparation and refinement of these emission inventories;
- Typical difficulties that may be encountered in attempting to utilize available data are as follows:
    - (i) Converting electronic data to a consistent or convenient format;
    - (ii) Reliable and accurate data entry (particularly where large amounts of information are involved);

(iii) Verification of database accuracies and completeness;

(iv) Establishing the existence or availability of information (e.g., useful statistics maybe maintained for reasons such as taxation, equipment maintenance, design documentation, property insurance policies, financial accounting, etc., and not be known to those charged with developing and maintaining the emissions inventory).

- The radiative forcing of vented waste gas volumes may be 7 to 12 times greater than that for equivalent flared volumes (depending on the gas composition and flaring efficiency). Consequently, these two activities must be considered separately. However, statistics on venting and flaring activities usually are available only as a combined volume and often are simply reported as flared gas. Even at the level of individual companies, many production accounting systems do not track flared volumes and vented volumes separately, or the ability to do so is not utilized. Consequently, all reported flared and vented volumes should be scrutinized carefully and some values may need to be adjusted;
- Except for acid gas flares and some continuous waste gas flares, flare and vent systems normally are not equipped with flow recorders. Consequently, reliable estimates of flared volumes can be difficult to obtain. Problems such as simmering or leaking pressure relief valves can be significant contributors to total flared or vented volumes and go unreported;
- Depending on the accounting procedures of individual companies, reported venting volumes may not include solution gas emissions from production storage tanks, vented volumes by gas operated devices and compressor starts, blowdown volumes from maintenance and repair activities, and still-column off-gas emissions from glycol dehydrators, and
- The concentrations of $CH_4$, $H_2S$, and $CO_2$ naturally present in the produced hydrocarbons may vary dramatically from one field to the next. These analyses may sometimes be obtained through government regulatory agencies. Otherwise, they must be obtained directly from the individual oil and gas companies.

## 2.4 Uncertainties

The potential sources of uncertainties in inventories of fugitive emissions from oil and gas activities may include the following:

- measurement errors;
- extrapolation errors;
- inherent uncertainties of the selected estimation techniques,
- missing or incomplete information regarding the source population and activity levels;
- poor understanding of temporal and seasonal variations in the sources;
- over or under accounting due to confusion or inconsistencies in category divisions and source definitions;
- misapplication of activity data or emission factors;
- errors in reported activity data;
- missed accounting of intermediate transfer operations and reprocessing activities (e.g., repeat dehydration of gas streams [in the field, at the plant, and following storage], treating of slop and foreign oil receipts) due to poor or no documentation of such activities;
- variances in the effectiveness of control devices and missed accounting of control measures, and
- data entry and calculation errors.

Due to the complexity of the oil and gas industry it is difficult to quantify the net uncertainties in the overall inventories, emission factors and activity data. While some semi-quantitative analyses have been conducted, a more thorough quantitative analysis is warranted.

High-quality refined emissions factors for most gases may be expected to have errors in the order of ±25 percent. Factors based on stiochiometric ratios may be much better (e.g., errors of ±10 percent). Gas compositions are usually accurate to within ±5 percent on individual components. Typically,flow rates have errors of ±3 percent or less for sales volumes, and ±15 percent or more for other volumes.

A high-quality bottom-up (Tier 3) inventory of fugitive methane losses from either oil or gas activities might be expected to have errors of ±25 to 50 percent. In comparison, default production-based emission factors for methane losses may easily be in error by an order of magnitude or more. Inventories of fugitive $CH_4$ and $CO_2$

emissions from venting and flaring activities will be quite reliable if the raw gaseous composition and actual vented and flared volumes are accurately known. Estimates of fugitive $N_2O$ emissions will be least reliable but will only be a minor contributor to total fugitive greenhouse gas emissions from oil and gas activities.

Estimates of emission reductions from individual control actions may be accurate within a small percentage of ±25 percent depending on the number of subsystems or sources considered.

# 2.5 Completeness

Completeness is a significant issue in developing an inventory of fugitive emissions for the oil and gas industry. A proper way of addressing this matter is through direct comparisons with other Parties. For refined inventories comparisons between individual companies in the same industry segments and subcategories is essential. This requires use of consistent definitions and classification schemes. In Canada, the upstream petroleum industry has also adopted a benchmarking scheme that compares the emission inventory results of individual companies in terms of production energy intensity and production carbon intensity. Such benchmarking allows companies to assess their relative environmental performance. Furthermore, it helps to flag, at a high level, anomalies or possible errors that need to be investigated and resolved. The factors presented in Table 5 also may be used to help interpret the results.

**TABLE 5**

**CLASSIFICATION OF GAS LOSSES AS LOW, MEDIUM OR HIGH AT SELECTED TYPES OF NATURAL GAS FACILITIES**

| Facilities | Activity Factors | Low | Medium | High | Units of Measure |
|---|---|---|---|---|---|
| Production and Processing | Net gas production (i.e., marketed production). | 0.05 | 0.2 | 0.7 | % of net production |
| Transmission Pipeline Systems | Length of transmission pipelines. | 200 | 2 000 | 20 000 | $m^3$/km/y |
| Compressor Stations | Installed compressor capacity. | 6 000 | 20 000 | 100 000 | $m^3$/MW/y |
| Underground Storage | Working capacity of underground storage stations. | 0.05 | 0.1 | 0.7 | % of working gas capacity |
| LNG Plant (liquefaction of regasification) | Gas throughput. | 0.005 | 0.05 | 0.1 | % of throughput |
| Meter and Regulator Stations | Number of stations. | 1 000 | 5 000 | 50 000 | $m^3$/station/y |
| Distribution | Length of distribution network. | 100 | 1 000 | 10 000 | $m^3$/km/y |
| Gas Use | Number of gas appliances. | 2 | 5 | 20 | $m^3$/appliance/y |

Source: Adapted from currently unpublished work by the International Gas Union, and based on data for a dozen countries including Russia and Algeria.

Smaller sources, due to their numbers and periods of activity, may often form significant total contribution. Therefore, they should not be disregarded unless their collective contribution to total fugitive emissions is proven to be negligible. Conversely, once a thorough assessment has been done, a basis exists for simplifying the approach and better allocating resources in the future to best reduce uncertainties in the results.

Many companies use computerized inspection-and-maintenance information management systems. These systems can be a very reliable means of counting major equipment units (e.g., compressor units, process heaters and boilers, etc.) for use in refined assessments. Also, some departments within a company may maintain databases of certain types of equipment or facilities for their own specific needs (e.g., tax accounting, production accounting, insurance records, quality control programs, safety auditing, license renewals, etc.). Some efforts should be made to identify such pools of potentially useful information.

## 2.6 Other important issues

### 2.6.1 Establishing baseline emission levels

If all the necessary historical data are present for the base year, emission estimates should be made using the *good practice* approach described in Section 2.1. Where some historical data are missing it should still be possible to use source-specific measurements made under the *good-practice* regime, and back-casting techniques to establish an acceptable relationship between emissions and activity data in the base year.

While establishing baseline emission levels is meaningful and important at a regional or national level, it is often a misleading indicator at the company level due to frequent mergers, divestitures and acquisitions in many areas. This may be an issue where national inventories are developed based on a rollup of company-level inventories, and some extrapolations or interpolations are required.

### 2.6.2 Imported/exported emission sources

In comparing fugitive emissions from the oil and gas industry in different countries it is important to consider the impact of imported and exported volumes of crude oil and natural gas. Otherwise, emissions viewed on either a per unit consumption or a per unit production basis will be misleading. Additionally, overall activity levels may be highly sensitive to price changes in some segments of the industry.

Production activities will tend to be the major contributor to fugitive emissions from oil and gas activities in countries with low import volumes relative to consumption and export volumes. Gas transmission and distribution and petroleum refining will tend to be the major contributors to these emissions in countries with high relative import volumes. Overall, net importers will tend to have lower specific emissions than net exporters.

# 3 REPORTING AND DOCUMENTATION

To promote transparency in the reporting of emission estimates it is important to also include reporting of the estimation methodology, sources of the emission factors and activity data, and the applied QA/QC procedures. The inclusion of various summary performance and activity indicators should be considered to help put the results in perspective (e.g., total production levels and transportation distances, net imports and exports, and specific energy, carbon and emission intensities). Reported emission results should also include a trend analysis to show changes in emissions and activity levels over time. The expected accuracy of the results should be stated and the areas of greatest uncertainty clearly noted. This is critical for proper interpretation of the results and any claims of net reductions.

The current trend by some government agencies and industry associations is to develop detailed methodology manuals and reporting formats for specific segments and subcategories of the industry. This is perhaps the most practical means of maintaining, documenting and disseminating the subject information. However, all such initiatives must conform to the common framework established in the *IPCC Guidelines* so that the emission results can be compared across countries.

Since emission factors and estimation procedures are continually being improved and refined, it is possible for changes in reported emissions to occur without any real changes in actual emissions. Accordingly, the basis for any changes in results between inventory updates should be clearly discussed and those due strictly to changes in methodologies and factors should be highlighted. Where changes in methodologies and emission factors are substantial, consideration should be given to updating previous inventories if practicable.

Specific recommendations for improvements in the current IPCC reporting formats through increased disaggregation of the oil and gas industry and capturing of missed categories are provided in Section 2.2.1.

The issue of confidential business information will vary from region to region depending on the number of players in the market and the nature of the business. The significance of this issue tends to increase downstream through the oil and gas industry. A common means to address such issues, where they do arise, is to aggregate the data using a reputable independent third party.

# 4 INVENTORY QUALITY

The basic elements of a QA/QC programme are delineated in the General Background Paper for the Expert Group Meeting on Good Practice in Inventory Development. More detailed requirements specific to the assessment of fugitive emissions from the oil and gas industry are presented in the subsections below.

## 4.1 Internal inventory quality assurance systems

Due to the complexity of the oil and gas industry, it is critical that the assessment effort be conducted in a thorough and well-organized manner. While much of the work is of a simple clerical nature and can be assigned to junior personnel, a team approach involving intermediate- and senior-level personnel is required to assure:

- accurate and complete posting of information;
- no double or missed counting, and
- correct selection and application of the applicable assessment methods and related factors.

Collectively, the team needs to be familiar with the target sources, applicable industry terminology, available assessment techniques, and sources of the required infrastructure and activity data.

### 4.1.1 Plant-level activities

Most companies in the oil and gas industry will have many facilities and a range of operations. Usually it is most appropriate to compile emission inventories at the individual facility level. In some cases company-level roll-ups are being conducted. This requires consistent reporting formats and application of definitions amoung companies. Furthermore, particular care is needed to ensure completeness and avoid double counting of emissions. Some companies are developing their detailed facility information over a series of years. The importance of credible data will be essential if emissions trading is ever established.

Inter-company comparisons are helpful for identifying anomalies and potential problems in the inventories.

### 4.1.2 Inventory agency level activities

Where a rollup approach is used to determine emissions for a particular segment of the oil and gas industry, checks must be made to ensure that either data are provided for all companies or a reasonable means for assessing emissions from missing companies is provided.

### 4.2.3 External inventory quality assurance systems

Audits and reviews of inventories should be considered as a means of improving the credibility of the reported results. They should be designed to confirm or determine:

- correct application of the selected methods;
- proper selection of emission factors;
- reliability of the chosen emission factors and activity data, and
- completeness and no double counting.

# 5 MAJOR RECOMMENDATIONS

The majority of the Parties currently reporting fugitive greenhouse gas emissions from oil and gas activities are applying Tier-3 methods. However, the *IPCC Guidelines* do not provide any guidance on the performance of such rigorous bottom-up approaches. Furthermore, there are varying degrees of Tier-3 approaches that may be applied. To achieve improved transparency, reduce the expert knowledge requirements, and promote simplified Tier-3 approaches as a reasonable alternative to the highly-inaccurate Tier-1 approaches, it is strongly recommended that detailed *IPCC Guidelines* for Tier-3 approaches be developed.

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# ANNEX 1 SUMMARY OF OIL PRODUCTION FOR SOME OIL PRODUCING COUNTRIES FOR THE YEAR 1997

**TABLE 6**

**SUMMARY OF OIL PRODUCTION FROM THE MAJOR OIL PRODUCING COUNTRIES AND REGIONS FOR THE YEAR 1997**

| Region | Nation | Oil Production (10 Mb/d) | Percent of Total |
|---|---|---|---|
| OPEC | Iran | 366 | 5.5 |
| | Iraq | 119 | 1.8 |
| | Kuwait | 208 | 3.1 |
| | Nigeria | 232 | 3.5 |
| | Saudi Arabia | 856 | 12.9 |
| | United Arab Emirates | 232 | 3.5 |
| | Venezuela | 331 | 5.0 |
| | Other OPEC Members | 492 | 7.4 |
| Non-OPEC | Canada | 189 | 2.9 |
| | China | 320 | 4.8 |
| | Mexico | 303 | 4.6 |
| | Norway | 315 | 4.7 |
| | Russia | 588 | 8.9 |
| | United Kingdom | 252 | 3.8 |
| | USA | 641 | 9.7 |
| | Other non-OPEC Members | 1183 | 17.9 |
| Total | World | 6627 | 100.0 |

Source:Adapted from information posted on the EIA web site at www.eia.doe.gov.

**TABLE 7**

**SUMMARY OF GAS PRODUCTION FROM THE MAJOR GAS PRODUCING COUNTRIES AND REGIONS FOR THE YEAR 1996**

| Region | Nation | Dry Gas Production (Bcf) | Percent of Total |
|---|---|---|---|
| North, Central and South America | Argentina | 102 | 1.2 |
| | Canada | 585 | 7.1 |
| | Mexico | 99 | 1.2 |
| | USA | 1879 | 23.0 |
| | Venezuela | 96 | 1.2 |
| | Other | 91 | 1.1 |
| Western Europe | Germany | 78 | 0.9 |
| | Italy | 71 | 0.9 |
| | Netherlands | 337 | 4.1 |
| | Norway | 145 | 1.8 |
| | United Kingdom | 317 | 3.9 |
| | Other | 60 | 0.7 |
| Eastern Europe and Former U.S.S.R. | Romania | 63 | 0.8 |
| | Russia | 2123 | 26.0 |
| | Turkmenistan | 131 | 1.6 |
| | Ukraine | 64 | 0.8 |
| | Uzbekistan | 170 | 2.1 |
| | Other | 76 | 0.9 |

| TABLE 7 (CONTINUED)<br>SUMMARY OF GAS PRODUCTION FROM THE MAJOR GAS PRODUCING COUNTRIES AND REGIONS FOR THE YEAR 1996 | | | |
|---|---|---|---|
| **Region** | **Nation** | **Dry Gas Production (Bcf)** | **Percent of Total** |
| Middle East and Africa | Algeria | 219 | 2.7 |
| | Egypt | 47 | 0.6 |
| | Iran | 138 | 1.7 |
| | Qatar | 48 | 0.6 |
| | Saudi Arabia | 146 | 1.8 |
| | United Arab Emirates | 128 | 1.5 |
| | Other | 138 | 1.7 |
| Far East and Oceania | Australia | 106 | 1.3 |
| | China | 67 | 0.8 |
| | India | 70 | 0.9 |
| | Indonesia | 238 | 2.9 |
| | Malaysia | 130 | 1.6 |
| | Pakistan | 70 | 0.9 |
| | Other | 141 | 1.7 |
| Total | World | 8173 | 100.0 |
| Source:Adapted from information posted on the EIA web site at www.eia.doe.gov. | | | |

# ANNEX 2 SOME USEFUL CONVERSION FACTORS

| TABLE 8<br>USEFUL CONVERSION FACTORS | | |
|---|---|---|
| **Physical Quantity** | **SI to English Conversion** | **English to SI Conversion** |
| Length | 1 m = 3.2808 ft<br>1 km = 0.6213712 mi | 1 ft = 0.3048 m<br>1 mi = 1.609344 km |
| Area | 1 $m^2$ = 10.7639 $ft^2$ | 1 $ft^2$ = 0.092903 $m^2$ |
| Volume | 1 $m^3$ = 35.3134 $ft^3$<br>1 $m^3$ = 6.2898108 bbl<br>1 L = 0.2641720 U.S. gal | 1 $ft^3$ = 0.02837 $m^3$<br>1 bbl = 0.15898729 $m^3$<br>1 U.S. gal = 3.785412 L |
| Velocity | 1 m/s = 3.2808 ft/s<br>1 km/h = 0.6213712 mph | 1 ft/s = 0.3048 m/s<br>1 mph = 1.609344 |
| Density | 1 kg/$m^3$ = 0.06243 $lb_m/ft^3$ | 1 $lb_m/ft^3$ = 16.018 kg/$m^3$ |
| Pressure | 1 kPa = 0.145038 psi | 1 psi = 6.89476 kPa |
| Energy | 1 kJ = 0.94783 Btu | 1 Btu = 1.05504 kJ |
| Energy/Unit Mass | 1 kJ/kg = 0.4299 Btu/lbm | 1 Btu/lbm = 2.326 kJ/kg |
| Energy/Unit Volume | 1 GJ/$10^3$ $m^3$ = 26.8405 Btu/scf<br>1 GJ/$m^3$ = 3.5879 mBtu/US Gal<br>1 GJ/$m^3$ = 150.69 mBtu/bbl | 1 Btu/scf = 0.037257 GJ/$10^3$ $m^3$<br>1 mBtu/US gal = 0.27871GJ/$m^3$<br>1 mBtu/bbl = 0.0066360 GJ/$m^3$ |
| Specific Heat | 1 kJ/kg·°C = 0.2388 Btu/$lb_m$·°F | 1 Btu/$lb_m$·°F = 4.1869 kJ/kg·°C |

| TABLE 9<br>USEFUL PROPERTIES OF METHANE[1] | | |
|---|---|---|
| **Physical Quantity** | **SI Units** | **English Units** |
| Global Warming Potential | 21 | 21 |
| Molecular Weight | 16.043 | 16.043 |
| Net (Lower) Heating Value | 33.936 MJ/$m^3$ | 909.4 Btu/$ft^3$ |
| Gross (Higher) Heating Value | 37.694 MJ/$m^3$ | 1010.0 Btu/$ft^3$ |
| Specific Volume at 15°C and 101.325 kPa | 1.474 $m^3$ gas/kg<br>1,474 $m^3$ gas/tonne | 23.654 $ft^3$ gas/$lb_m$<br>47,308 $ft^3$ gas/ton |
| Density at 15°C and 101.325 kPa | 0.678 kg/$m^3$<br>0.678 tonne/1000 $m^3$ | 0.042 $lb_m$/$ft^3$<br>0.021 ton/1000 $ft^3$ |

[1]While natural gas is primarily methane (usually 85 to 98 mole percent), it also contains other heavier hydrocarbons and some impurities such as $CO_2$, $N_2$ and $H_2S$. Accordingly, natural gas will have somewhat different properties than pure methane, and these values may vary dramatically between reservoirs and even across a given processing facility.

| TABLE 10<br>TYPICAL ENERGY-CONTENT FACTORS FOR HYDROCARBON SALES VOLUMES[1] | | |
|---|---|---|
| **Type of Hydrocarbon** | **SI Units** | **English Units** |
| Natural Gas | 37.4 GJ/ $10^3$ $m^3$ gas | 1,000 Btu/scf |
| Ethane | 18.5 GJ/ $m^3$ liquid | 2.79 mmBtu/bbl |
| Propane | 25.4 GJ/ $m^3$ liquid | 3.83 mmBtu/bbl |
| Butanes | 28.2 GJ/ $m^3$ liquid | 4.25 mmBtu/bbl |
| Oils | | |
| Light-and-medium Crude Oil | 38.5 GJ/ $m^3$ liquid | 5.80 mmBtu/bbl |
| Heavy Crude Oil | 41.4 GJ/ $m^3$ liquid | 6.24 mmBtu/bbl |
| Bitumen | 42.8 GJ/ $m^3$ liquid | 6.45 mmBtu/bbl |
| Synthetic Crude Oil | 39.4 GJ/ $m^3$ liquid | 5.94 mmBtu/bbl |
| Pentanes Plus | 33.1 GJ/ $m^3$ liquid | 4.99 mmBtu/bbl |

[1]Based on the gross (or higher) heating value of the product.

# ANNEX 3 TYPICAL COMPOSITION (MOL PERCENT) OF PROCESSED NATURAL GAS

**TABLE 11**

**TYPICAL COMPOSITIONS (MOL PERCENT) OF PROCESSED NATURAL GAS**

| Origin[1] | Hydrogen | Carbon Monoxide | Hydrocarbons | | | | | | | | Oxygen | Other | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $H_2$ | CO | $CH_4$ | $C_2H_4$ | $C_2H_6$ | $C_3H_6$ | $C_3H_8$ | $C_4H_8$ | $C_4H_{10}$ | $C_5H_{12+}$ | $O_2$ | $N_2$ | $CO_2$ |
| Algeria 1 (LNG) | ND | ND | 91.2 | ND | 6.5 | ND | 1.1 | ND | 0.2 | ND | ND | 1.0 | ND |
| Algeria 2 (LNG) | ND | ND | 88.6 | ND | 8.2 | ND | 2.0 | ND | 0.6 | Traces | ND | 0.6 | ND |
| Canada[2] | ND | ND | 95.1 | ND | 2.4 | ND | 0.1 | ND | 0.1 | Traces | ND | 1.7 | 0.6 |
| North Sea | ND | ND | 88.2 | ND | 5.4 | ND | 1.2 | ND | 0.4 | 0.2 | ND | 3.2 | 1.4 |
| Russia | ND | ND | 96.2 | ND | 1.2 | ND | 0.3 | ND | 0.1 | 0.1 | ND | 1.8 | 0.3 |
| Groningue | ND | ND | 83.5 | ND | 3.6 | ND | 0.7 | ND | 0.2 | 0.1 | ND | 10.8 | 1.1 |
| USA[3] | ND | ND | 93.4 | ND | NA | ND | NA | ND | NA | NA | ND | NA | NA |

ND - Either no data or none detected.
NA - Not Available.
[1] Source (except as otherwise noted): personal communication with Marc Darras of Gaz de France dated July 9, 1999.
[2] Source: GRI Canada (1998) for average gas compositions at the Alberta/Saskatchewan border.
[3] Source: Radian International (1996).

**TABLE 12**

**TYPICAL COMPOSITIONS (MOL PERCENT) OF PROCESSED LIQUEFIED PETROLEUM GASES (LPGS)**

| Origin[1] | Hydrogen | Carbon Monoxide | Hydrocarbons | | | | | | | | Oxygen | Other | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $H_2$ | CO | $CH_4$ | $C_2H_4$ | $C_2H_6$ | $C_3H_6$ | $C_3H_8$ | $C_4H_8$ | $C_4H_{10}$ | $C_5H_{12+}$ | $O_2$ | $N_2$ | $CO_2$ |
| Propane | ND | ND | ND | 0.5 | 2.0 | 30.0 | 65.5 | ND | 2.0 | ND | ND | ND | ND |
| Butane | ND | ND | ND | 3.2 | ND | ND | 6.1 | 21.8 | 68.6 | 0.3 | ND | ND | ND |

ND - Either no data or none detected.
[1] Source (except as otherwise noted): personal communication with Marc Darras of Gaz de France dated July 9, 1999.